COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of: Preparation of the 2007 Integrated Energy Policy Report (2007 IEPR)	Docket No. 06-IEP-1D

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, JUNE 7, 2007

9:00 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

James D. Boyd

Jeffrey D. Byron

John Geesman, Associate Member

ADVISORS PRESENT

Susan Brown

Melissa Jones

Kevin Kennedy

Gabriel Taylor

Tim Tutt

STAFF and CONTRACTORS PRESENT

Leon D. Brathwaite

Catherine Elder, RW Beck, Inc.

James Fore

Youssef Hegazy, PhD, RW Beck, Inc. (via telephone)

James T. Jensen, Jensen Associates

Dale Nesbitt, PhD, Altos Management Partners, Inc.

Michael G. Purcell

Angela Tanghetti

Ruben Tavares

Lorraine White

Bill Wood

ALSO PRESENT

Bevin Hong Jr., TransCanada

Robert S. Cowden, Pacific Gas & Electric Company

David L. Arthur, PhD, Redding Electric Utility

Steven R. Schiller, University of California, California Institute for Energy and Environment

Mark P. Sweeney, California Natural Gas Vehicle Coalition

Richard Myers, California Public Utilities Commission

Jill Scotchi, Pacific Gas & Electric Company

Kevin Billings, Kern River Gas Transmission Company

Rory Cox, Pacific Environment

Alvin Pak, Sempra Energy (Sempra LNG)

Herbert S. Emmrich, Southern California Gas Company and San Diego Gas & Electric

Gary M. Yee, Air Resources Board

George Clavier, Pacific Gas & Electric Company

I N D E X

P R O C E E D I N G S

9:05 a.m.

PRESIDING MEMBER PFANNENSTIEL: We can be underway. This is a workshop of the Integrated Energy Policy Report Committee on Natural Gas Market Assessment. It is, as you can see, of great interest to the Commission. We have four of us here to participate in this. I'm Jackie Pfannenstiel, the Commission Chair and the Presiding Member of the Integrated Energy Policy Report Committee. To my left is Commissioner Jeff Byron, to my right Commissioner Boyd. To his right, Commissioner John Geesman, and to Commissioner Geesman's right his staff advisor, Melissa Jones.

A full agenda that I think everybody has in front of you so why don't we begin. Ruben.

MR. TAVARES: Good morning, Commissioners. As you know we have a full agenda for today. Hopefully we'll enjoy it. Before we start some housekeeping items. This workshop is being tape-recorded and also webcast on the Internet.

Phone calls, you can make a phone call to 1-800-857-6618. The passcode is IEPR and the leader is Lorraine White. Those on the phone please identify yourselves for the record when making a comment or asking a question. And please put your telephone on mute while waiting. Otherwise, you know, any noises on your end will broadcast in the hearing room.

For those in the room, the restrooms and telephones are on the patio to the left as you leave the front door of the hearing room. Coffee, beverages are upstairs on the second floor. And also we are asking everybody to please silence your cell phones. If you need to make a call please go outside to the patio.

Agenda, copies of the preliminary report and presentations are on the table outside. Hopefully you will get a copy and follow the presentations. We have scheduled through around 3:30 this afternoon. If we finish early we will leave early but hopefully no later than 3:30.

When making a comment please go to the telephone, identify yourself and pose a question.

Again, we have the IEPR Committee and also the Natural Gas Policy Committee with us. Commissioner Pfannenstiel, would you like to make a comment?

PRESIDING MEMBER PFANNENSTIEL: I have no opening comments. Other Commissioners?

COMMISSIONER BYRON: No.

PRESIDING MEMBER PFANNENSTIEL: No? Go ahead.

MR. TAVARES: No comments, okay.

First we are going to have Lorraine White. She is going to make a presentation on how the Natural Gas Assessment Report actually fits into the overall IEPR. So Lorraine.

MS. WHITE: Good morning, everyone. My name is Lorraine White and I am a program manager for the Integrated Energy Policy Report proceeding.

Today's workshop is a very important part of the record on which the Energy Commission will be building the 2007 Integrated Energy Policy Report. The relationship between natural gas supplies, price, infrastructure and demand has an impact on not only the availability of this resource to meet the needs of consumers but it also is related to the electricity sector, the effects of the availability of supplies and demand there as well as price.

As we heard last week the natural gas

resources are also an important part of emerging transportation alternative fuels and has a lot of interrelationships with other types of energy markets.

The Integrated Energy Policy Report requires the Energy Commission to look at, assess and forecast supply, demand and price for various energy resources and look at the interrelationship between those resources and markets.

This particular IEPR is looking not only at the electricity market, the natural gas market, petroleum markets and other fuel markets that meet the demands and needs of California and the West but we are also looking at topics related to efficiency. How these demands actually occur in California, in particular how land uses are affecting demand and supply and infrastructure. Looking at the different alternatives, looking at emerging technologies, research opportunities. The drivers that affect cost and what types of issues we'll be facing in the future, particularly in a post-AB 32 world.

From these assessments and forecasts we are going to be developing policy recommendations that will be addressing the various types of issues exposed by these forecasts and assessments related to the adequate supplies and resource provision to California to meet its needs. We rely on the input of various groups and entities to ensure that we have a robust assessment and forecast on which to build these recommendations. We look to market participants and other agencies to participate in this proceeding so that we can come up with the best assessment and forecast as well as recommendations as possible.

The legislation requires that we revisit these assessments and forecasts every two years and in intervening years develop updates on the most particular and salient issues of the time. In this particular instance we have benefited a great deal from input from various market participants, cooperative participation by the PUC and the CA-ISO and we look forward to today continuing that dialogue.

We are at a critical part in the proceeding. Right now we are developing a lot of the draft reports that document the assessments and forecasts that we are doing. Today's workshop is an example of that.

As we refine these reports and

assessments with the input we are getting from various parties we hold a lot of the workshops to try and get that input to refine it, to build off of previous discussions. For example, the March 6 workshop n the staff's assessment proposal and methodologies. But then also to produce final documents on which we will actually craft the Committee Integrated Energy Policy Report.

In late August we will be publishing that document and having hearings on that document in September. With the goal, of course, to have the whole Commission adopt the 2007 Integrated Energy Policy Report by October 24.

All of the information we are generating as part of this proceeding we make available on the Commission's website. Any questions or comments that you might have which you don't necessarily know quit how to fit into the record you can always contact me. Also to get information about other related topics that the Commission is looking at as part of this proceeding. Particularly when it comes to natural gas I refer you Ruben Tavares.

Just for your information and related to the idea that we are developing an Integrated

Energy Policy Report proceeding, there are some other workshops that we will be holding in which natural gas will be discussed. And in particular I will draw your attention to the scenario workshops that are coming up later this month and in July. That information can also be found on the website.

If there's any questions I'd be happy to answer them. Thank you.

MR. TAVARES: Okay, so what is the purpose of the workshop today? As you know we are presenting a preliminary assessment report on natural gas and we are soliciting comments and suggestions from the public and the Commissioners on our results. We, the staff of the Energy Commission, in conjunction with contractors and consultants, we developed this forecast. So we are asking for all your suggestions and comments.

As Lorraine mentioned a few minutes ago, we are going to put together the final report. We are planning to have the report by the end of July. Then there is going to be another proceeding by the middle of August. We are going to try to integrate, you know, the results that we have on natural gas with the scenario project.

But we will talk a little bit more about that, you know, by the end of this workshop.

On March 26 of this year we conducted a workshop. It was a staff workshop to request input on the staff's assumptions that we were planning to use in our model. The model that we lease from Altos is the North American Regional Model, Gas Model.

And we received some comments and we discussed these comments with the Commissioners and some of the advisors and we incorporated some of those comments into our results. So what you use today is going to be a reference case that we developed given those assumptions. So we are asking again for more comments today on our results.

As a difference from the past, in the past we had more or less a single point forecast in our natural gas assessment. In this 2007 natural gas assessment we are putting less emphasis on a point forecast and more on some alternatives. Again, our assumptions and inputs are just the set of assumptions that we think are the best. However, those assumptions and those variables can change and if they change our output will change.

As I mentioned before we used NARG, the North American Regional Gas Model, to develop the reference case. To determine demand, supply, infrastructure and prices of natural gas.

Staff also used the NARG model to run four different sensitivities. In other words we just modified one variable to see what kind of results we would get. We had four of them, two on the oil price, one was using the high oil price another one low oil price, and two additional, LNG, liquified natural gas, one facility in Southern California and another one in Oregon. Those were separate, separate sensitivities.

We also received assistance from RW Beck. They helped us analyze the assumptions and variables that we had in our reference case an they gave us some potential alternatives. And we will have a presentation this afternoon on, you know, what are those alternatives and uncertainties involved in forecasting, again, demand, supply, infrastructure and prices of natural gas.

The Commission also hired Mr. Jim Jensen. He is a very well-known expert on liquified natural gas. He is going to make a presentation this morning on the current status of worldwide natural gas supply, demand and transportation cost.

Mr. Jensen developed the base case, what he calls reference case scenario, and two alternative scenarios. One, a high scenario reflecting market optimism on liquified natural gas, and a second scenario reflecting concern on the supply side of liquified natural gas.

Our first presentation is going to be on liquified natural gas and Mr. Jim Jensen is going to present his results of a study that he conducted so far. So, Mr. Jensen.

MR. JENSEN: Good morning. I am pleased to be invited here this morning to discuss the study work that we have done for the Commission on liquified natural gas, a topic that, of course, is of great deal of interest today.

Until the mid-1990s world LNG trade was really defined by two characteristics. It was largely Pacific Basin trade. As recently as 1994, 77 percent of all LNG supply originated in the Pacific Basin, 74 percent of all LNG demand was in the Pacific Basin. In fact, interesting enough at that point the gas utilities in Tokyo, Osaka and Nagoya accounted for half of world LNG trade.

But that began to -- The second part of the pattern was that it was based on long-term contracts which were essentially destination inflexible. They linked specific buyers and specific sellers and you knew where the stuff was coming from, you knew where it was going.

But that whole pattern began to change in the late 1990s. Demand began to surge as gas-poor countries such as Spain, Turkey, China, India got interested in gas-fired combined cycle generation and looked to LNG for gas supply.

And at the same time you began to see the, you began to see the traditional consumers in North America and Europe finding the limitations on their traditional sources of domestic and pipeline supply. So they became interested in LNG as well. This brought forth a burst of new capacity additions which came in in the Atlantic Basin and in the Middle East.

Basically the demand increases have changed the structure as well. The traditional long-term contract fell victim to the worldwide restructuring of the gas industry. The traditional contract was based on the assumption that it was a sharing of risk between buyer and seller. And the comment was essentially, the buyer takes the volume risk by absorbing a take or pay contract, the seller takes the price risk in a price clause. And that essentially was risk-sharing mechanism.

As North America restructured its industry, deregulated and went to gas-to-gas competition it became almost impossible to sell an oil-link contract in a gas-to-gas competitive market so that structure really went by the boards. And it has gone by the boards in the UK, which has also restructured its industry.

But that has had a subtle effect because in a sense what has happened is that if you link the long-term contract price clause to a gas market indicator like Henry Hub in the US or to the National Balancing Point in the UK, it makes it much simpler for the buyer to absorb risk because if he doesn't like the cargo when it arrives he can turn around and sell it in the market.

So risk has migrated upstream to the sellers. And the sellers have responded in many ways by a new form of operation in which essentially they contract, what I call self-contracting for supply at the well head, and they move it through their own outlets downstream. So in other words, a shell having participation in a particular LNG plant will essentially buy the stuff off that and move it to its affiliates in the US or Europe.

A small, short-term market has developed, a spot market, maybe 12, 14 percent of total. And the fact that the self-contracting exists means that the sellers are much more able to move volumes to the markets that want it. For example, ABG has access to capacity in Trinidad, it has access to capacity in Egypt, it has terminal capacity that it controls in the US, it has terminal capacity that it controls in the UK, and it can look at the National Balancing Point price or the Henry Hub price and decide where to divert its internal supplies.

What that has done essentially is created a much more flexible and global market. The Pacific Basin is not really quite a part of that yet, and yet because the Middle East is the center for shipping east and west, in effect what you have is a price arbitrage between the Pacific Basin market and the Atlantic Basin market via the Middle East. So what we now have is a global gas market in which pipelines compete with LNG and the price signals are moved around the world by LNG pricing.

The current outlook for LNG has become highly uncertain because of a number of reasons. First of all there is an unexpectedly sharp increase in demand, particularly in North America, Spain and the UK. These markets decided they wanted LNG fairly quickly and the demand increased very rapidly.

At the same time the normal lag in putting projects together, including approvals and plant construction four years or more meant that supply could not respond quickly to the increase in demand. And what we have essentially had, we've created a shortage, a worldwide shortage of supply because of the lags between demand and supply.

The fact that the surge in plant construction came about essentially overwhelmed the capability of the sophisticated design constructors and equipment suppliers who supply the business and what we have had is an almost unprecedented increase in costs.

It was fashionable until several years ago to talk about the fact that LNG costs were steadily coming down. And at that point it began to look as if the target was something like for an LNG plant, $200 of capital cost per ton of capacity. Now people are talking $400 to $600 a ton as the norm but it is a very uncertain and very unstable market.

And there are several projects that have come in either with cost overruns or for new bids that range between $1,000 and over $1,200 a ton, a very dramatic increase in costs. I mean, essentially what's happened, there are a limited number of people who know how to do these things very well and they don't answer the telephone anymore because the demand is so high. And this has caused, obviously, some very serious problems.

The fact that we have had a sharp rise in oil and other energy prices raises questions about demand response. Are we going to get demand elasticity, are we going to get a fall-off in demand so we'll forecast change. And also what happens to interfuel competition? Coal has not responded, for example, in China at nearly the rate that gas has responded. So if you look at the Chinese demand you say, how is the balance between gas and coal in China been shifted?

The political reaction to global warming and how it will affect competition between coal and gas for power generation. An important indication of China. China is now about to pass the US as a carbon emitter and obviously a lot of that is because they use coal for power generation. But at the moment with the prices what they are the Chinese are economically dedicated to coal. And until they decide to clamp down on coal use gas will be affected.

And then there are the questions of geopolitical issues that will determine when and how LNG projects will go forward in supplying countries. And those are very important issues.

And finally, LNG is sensitive to small changes in the world's gas supply/demand balances. Essentially it is a small part of the gas supply/ demand balance. And in a country importing LNG, if there is a small change in a little bit of LNG and a lot of domestic production, like in the US, a small change in either demand or supply not matched by the other has a very powerful levering effect on the demand for LNG. All of these cause uncertainties that are things you have to deal with.

My study addressed these issues by utilizing three illustrative scenarios: First a base or reference case, second a high case reflecting earlier market optimism, and third, a low case reflecting concerns about supply.

Forecasts in the early 2000s tended to be very optimistic about the demand for gas and particularly about LNG. If you can generalize about forecasts in the middle 1990s, world forecasts tended to become much more optimistic about natural gas as the enthusiasm for gas-fired power generation took hold.

And at that point the assumption was that there was for countries that had domestic supplies, significant domestic supplies like the US or like parts of Europe, that there was enough domestic supply to absorb or to handle this increased growth and demand. So at that point if you look at, for example, the EIA projections of the US, LNG did not play a big role in their estimates in the late 1990s.

Then as concerns for supply began to develop the forecasts tended to continue the growth and demand but assumed that LNG would replace the loss of local supply. So there was a big increase in LNG forecasts. A lot of optimism about LNG.

More recently with the increases in costs and with the facts that prices are much higher and people are not certain how things will go ahead, there has been a tendency to scale down both demand estimates and LNG forecasts. My high case assumes that the old optimism is still right. My low case, we're transferring a lot of the new supply to countries that have geopolitical or technical issues. And it assumes that some of those may turn out to be difficult to deal with and so the low case is pessimistic about supply on that basis.

And here simply are the three scenarios showing the earlier LNG optimism, the base case and the current long term supply concern.

For at time, as I say, LNG costs were declining and it was assumed that the trend would continue and stimulate LNG trade. But that trend has been dashed by the cost increases from the overloaded project industry.

And to illustrate why it's such a problem it is interesting to look at what I would call the order book. In this business where you're looking, the plants that are underway now may not come on, some of them will not come on for four years. You can kind of look four years ahead and treat the next four years as the order book. In other words, the projects that are due to come on in the next four years are already in the train so they are a part of the order book.

And if you look historically at the order book pattern going back in time, each of these years shows the plants that were designed to come on stream for the following four years. You can see how sharply that has increased and caused tremendous problems in terms of the supply characteristics of the industry.

Now I have maintained some internal, what I call cookbook models of LNG economics so I can run them in any project that I want to and I have them back in time so it is possible for me to sort of reconstruct the history of what I would have thought at periods in time in the past. And this slide simply shows you the -- there we go.

This slide shows you an estimate that I might have made for a movement from Australia to Southern California in 1996 showing liquefaction costs, tanker transportation costs and regasification.

But costs were coming down. That's the estimate that might have been made in 2000 with a significant reduction in cost. By 2003 it was down again. But as you can see in this estimate it has gone right back up again. Most of the increases in the liquefaction costs because tankers have not been so badly affected.

Now I would have to say that is highly speculative because I talk to a lot of people in the industry and nobody can agree what has happened to costs. And I would have to say that my estimates are probably on the conservative side because I do not believe that a dramatic increase such as we have had necessarily carries forward to the long term. But the current feeling in the industry is that their prices are even higher. But as you can see, speculative or not, the idea that costs are declining is now gone.

ASSOCIATE MEMBER GEESMAN: Were those for actual estimates that you made over the period of those 11 years or is that you constructing

today what you might have said in each of those
years?
MR. JENSEN: Yeah, I mean I have the models. I have the assumptions of the model at the period so I ran the 1996 estimates, I ran the 2000 estimates, I ran it in my current model. It's the same model but I say, what did I assume in 1996, what do I assume in 2000. It's essentially done that way.
ASSOCIATE MEMBER GEESMAN: Then you've adjusted those all for 2007 dollars?
MR. JENSEN: No. They're essentially dollars, pretty much dollars of the day.
ASSOCIATE MEMBER GEESMAN: Okay.
MR. JENSEN: Okay. Where will the LNG come from? Resources, technology and geopolitics. The world's reserves of natural gas are very large and the resource base is large. More than adequate to support gas trade far into the future. And I would have to say that I see no supply problems in supporting any of my three scenarios out to 2020.
But of those reserves many of those reserves are either already committed to existing methods such as domestic markets or committed on

international trade. And a big block of those reserves are what I call deferred reserves. They are reserves that are associated with oil production. They may be gas dissolved in oil in Saudi Arabia that is not going to be produced until far into the future. They may be big gas caps in Iran that aren't going to be tapped because they would affect oil production levels. They may be gas going in for re-injection.

But despite all of that a very large percentage of the reserves are still available, are uncommitted. Roughly slightly more than half of the world's reserves are not committed to any other use so there are very large reserves, reserves now existing.

But 84 percent of the reserves that are uncommitted are located either in the Middle East or in the former Soviet Union and there are geopolitical or technical issues for both regions.

To stress the geopolitical questions. If you look at 1998 when the LNG business began to take off and look forward to about 2012, which is really sort of in train with projects that are going forward, five countries accounted for 75 percent of world LNG supply.

They are Qatar, that itself represents a third of the total, they are Egypt, Trinidad and Nigeria, each of which is about ten percent, and Australia slightly less. So those five countries all represent the increase in LNG liquefaction capacity between 1998 and 2012.

In my forecast looking out from 2012 to 2020, in my base case there are five countries that represent 75 percent of it but three of the countries that are on the first list have dropped from the second list.

Qatar is gone because Qatar has decided as a matter of policy that once the current major expansions are complete they are going to sit and wait for awhile and see what to do and it is not clear when they'll come back online. Trinidad is a small country. It has only a limited amount of area to go looking for gas to support the kind of growth that it's had. And Egypt may come back, it depends on how fact exploration goes there.

But the countries that have substituted those three countries are Venezuela, they are Atlantic Russia and they are Iran. And so in a sense you have raised in each of those countries geopolitical issues that really aren't concerns in the first one.

And I'd have to say that the leading country in the out years is Nigeria. And if you look at Nigeria at the moment what you see is tremendous civil unrest to the point where bandits are capturing people off rigs. Some of the major companies have shut-in their production for months. It is not an environment that is conducive to large, up-front capital expenditures. So these geopolitical issues obviously are a part of looking forward.

Now obviously when I do the difference between the base case and the low case I am much more concerned about those. When I do the base case I assume that today's politics don't last forever and I think that's a reasonable assumption.

The Pacific Basin markets have been extremely tight in part because of Indonesia. Indonesia has been until quite recently the world's largest LNG supply but it is now the sick man of Asia. It has very big political problems and geological problems and at the moment it is failing to deliver on its contracts. This year the expectation is that Indonesia will be ten percent below its contract commitments to Japan and it is in the process of buying spot cargos from other countries to honor its contract commitments.

But a lot of the future supply in the Pacific Basin will come from Australia, both from Western Australia and the Timor Sea.

Indonesia will be a mixed bag because they are having trouble with their existing plants but they seem committed to go ahead with expansions such as Tangou, which is going forward. So there will be growth but there will also be shrinkage there.

But if the Pacific Basin supply is limited a lot of the future supply for Pacific Basin markets will have to come from the FSU or the Middle East.

Russia's Sakhalin Island has a great resource potential but geopolitical issues have raised questions about how much will be made available beyond the Sakhalin II Project, which is the Shell project now under construction.

If you followed the press, Sakhalin II by Shell has had what the economists call the world's greatest private capital cost overrun in history. Originally budgeted at $10 billion it is now budgeted at $20 billion and is expected to go to $23 billion. That has led to a lot of dispute between the Russians and Shell.

A lot of other issues are involved including the geopolitical ambitions of the Russian administration. But the fact of the matter is that Gazprom has now assumed the operating control from Shell in Sakhalin II. It is going to go forward but obviously the old role was changed. And that question is, how will Sakhalin develop in the future?

Now Russia has major policy issues that have to be resolved in Western Siberia and the Offshore Barents Sea. They have traditionally been a pipeline supplier to Europe. They have now become interested in diversifying both into LNG and into moving into the eastern markets such as China. And so the question of how that policy develops will affect the amount of LNG that is available.

This sort of is a map of the major export basins of the former Soviet Union. Nadym Pur Taz up here in Western Siberia is essentially the workhorse of Europe, of the European supply.

Russian exports to Europe, to continental Europe, amount to about 25 to 30 percent of the total and Nadym Pur Taz is where the bulk of them come from.

It has the world's second and third largest gas fields but they are now in decline. They brought a new gas field on line recently. There's still a lot of gas there. It's only the decline is the equivalent of two billion feet a day per year. That's roughly the equivalent of LNG exports out of Algeria.

The issue that people have been looking at is will the Russians be willing to expand based on Nadym Pur Taz. There is gas there. Or do they want to move to some of the other gas that they've got which is the Yamal Peninsula or offshore Barents Sea in Shtokman. That would enable them to diversify their supply sources. There are very large reserves there.

The Russians have made enemies, unfortunately their biggest customers in Europe, partly because of the political problems with Ukraine interrupting supply, the fact that they refused to open their -- to create open access to let independent producers compete for markets in Europe.

And as Europe has been tending to move to LNG as a diversification option, when the US got interested in LNG, it began to look as if the -- to the Russians as if the Russians had a diversification option in LNG to the United States out of Shtokman. They originally were talking about moving the Yamal Peninsula down into the continent, then they got interested in Shtokman. Now Shtokman is 300 miles offshore Murmansk under shifting ice so it is a technological problem as well as a political problem.

More recently they seem to have backed off that. They have backed off cooperation with the companies, they have backed off interest in LNG and it's not clear which way they go. But if they decide to go the comfort way to pipelines that will affect LNG supply and will affect the way in which the relationships between the Europeans and the Russians proceed.

The other interesting question of course is that when you go to international meetings and see Russian presentations they envision some sort of a pipeline system that runs from Sakhalin through Irkutsk up to Western Siberia that will feed Asian markets. Now Irkutsk is the big gas field that is expected to come into China. Difficult negotiations between the two countries.

If Sakhalin is linked and they decide to go the pipeline route out of that link that will affect the amount of LNG that is available out of Sakhalin. So that is not, clearly not a question obviously resolved as yet.

You might have seen in the press that the problems that existed for Shell in Sakhalin are now beginning to surface with BP in Irkutsk. Suggesting what worries a lot of people, that the Russian policy is to take control of all its gas and its gas exports and eliminate the role of the companies in trying to decide where the stuff goes.

The Middle East will be the dominant incremental supplier in the Pacific Basin between now and 2020. But 61 percent of the Middle East's uncommitted gas is in a single gas field shared by Qatar and Iran, the north field in Qatar, the south part is in Iran.

And if one includes the additional uncommitted gas in Iran, those two countries account for nearly 90 percent of the uncommitted gas in the entire Middle East.

Qatar has declared a moratorium on further LNG expansion beyond 2012 and Iran is under international sanctions.

Qatar's caution plus Iran's geopolitical constraints thus make it difficult to project the quantities and timing of additional Middle East supplies beyond 2012. Everybody expects it to be important but it is very hard to figure out how you schedule it given these questions.

Okay, the demand projections. While Northeast Asia once dominated LNG trade it is being surpassed by the Atlantic Basin.

Construction underway will provide a bulge in supply. And I think because the market is undersupplied that will be met by a bulge in demand and so my reduced growth rates take place after 2012.

By 2020 OECD Europe in the Atlantic Basin will provide the largest regional market, although if you combine the Atlantic and Pacific North America it is somewhat larger.

And Europe provides a very strong market in the high case, but in the low case if there is less LNG the assumption is that you are able to depend much more on pipeline supply. Northeast

Asia is pipeline dependant for interregional trade, North America is LNG -- I'm sorry, let me say that again. Both Northeast Asia and North America are LNG dependant for international/ interregional trade. Europe has the pipeline option. So you would expect in the low case to see much more pipeline supply and much less LNG.

And here are simply the base case projections showing Pacific Basin, Atlantic Basin. And I include the Indian Subcontinent really in this Middle East sphere or influence.

Supply projections: With Qatar leading the way, Middle East supply will grow rapidly between now and 2010. Thereafter growth will be more modest. Australia is growing rapidly in the Pacific Basin, Southeast Asia is not.

The Atlantic Basin will benefit from major additions in North and West Africa, particularly in Nigeria. Soon Iran in the Middle East and Russia in the Atlantic Basin will become important exporters during the latter part of the forecast. And here is the supply projection. And as you can see the shifting of balance between the various regions.

In conclusion, in all three studies,

scenarios in the study, LNG demand will experience high rates of growth.

There are substantial uncertainties in the way in which demand will develop and will be supplied.

The way in which world gas demand responds to a high energy price/high cost environment will be an important determinant of how much LNG will be needed.

And the rate at which supply will be made available will depend in large measure on how suppliers deal with the technical, economic and geopolitical uncertainties in some of the future supply options.

MR. TAVARES: Are there any questions, Commissioners? Any questions from the public?

COMMISSIONER BYRON: Yes, Ruben.

MR. TAVARES: Okay.

COMMISSIONER BYRON: There was a great deal of information. Would you give that presentation again, please.

(Laughter).

COMMISSIONER BYRON: I saw the longer version as well, it was very good. Just a couple of questions that are related, at least I'm going to relate them. The first is, and maybe you covered this. But with regard to liquefaction or the sending and the receiving terminals. Is there an imbalance there at this time, or as you say in the booked projects, we do have a shortage of liquefaction right now?

MR. JENSEN: Yes, we do have. Essentially it's a tight market. There is not enough liquefaction capacity to meet demand, that has been the case. That may be softening. And in fact the sort of common view on the street is that the market is tight and will stay tight forever. My calculations say that this surge of supply that is coming on in 2009 and 2010 may in fact create quite a surplus during that period.

Now when you look at capacity for regasification terminals, that's a very complex issue. The reason is that capacities are stated by people in different ways. In a regasification terminal the gasifier is fairly cheap as a part of the terminals and it is very easy to over-size it if you have an intermittent demand. You can use it for peaking but the capacity of the storage tanks and the capacity of the pier to handle tankers may limit how much of that capacity you could use over the year.

So people talk in terms of peak capacity and people talk in terms of annual or sustainable capacity. And the trouble is everybody's international figures add apples and oranges, they add both. If you look at Japan, their peaking capacity -- they report on a peak basis and they have 30 percent capacity factor. They buy on a 90 percent take or pay contract so obviously their annual view is at 90 percent. So it is very hard to say whether, what the capacity relationship is in receipt terms.

COMMISSIONER BYRON: Thank you. Given the demand by region projections that you show and the increasing Pacific demand, and I'm not sure if you re able to answer this. But if we only look at the supply and demand situation throughout the world that you have indicated would it make sense for us to look at a different model for the way we develop LNG receiving in the Pacific Region of the US? For North America I should say. For instance, would it make sense for utilities to perhaps get in the business of procuring long-term contracts of LNG and perhaps even building LNG terminals?

MR. JENSEN: The Pacific market is a totally different market contractually than the Atlantic Basin market. The Atlantic Basin market with the UK on one side and North America on the other side, gas-to-gas competition, contracts have totally changed, the battle line between the European oil link contract pricing runs down through the North Sea. How that will be resolved will take place in time.

The Pacific, the Pacific Basin is still very much a long-term contract, fairly inflexible system and will be very slow to change. To the extent that you're part of the Pacific Basin supply it suggests that it may be in your interest to be somewhat more conservative than the market enthusiasts would suggest, if you know what I mean. Because it may make much more sense to have long-term contracts.

At the same time arbitrage in the Pacific will be a much more difficult issue because in the Atlantic you have got supply on both of the Atlantic, you've got markets on both sides of the Atlantic. In the Pacific you do not have an American Pacific supply to arbitrage. And if you're shipping LNG from Indonesia to Japan and all of a sudden an option to make a spot cargo develops to ship one to North America, it takes three times the tanker capacity to ship the same amount of stuff. So it is not a very good arbitrage market.

I don't know that that's answered your question but I think long-term contracts will be more important for you than they might be for somebody in the east.

COMMISSIONER BYRON: Thank you, Mr. Jensen.

MR. JENSEN: And if they're utility-oriented that's -- a utility may be better able to write one than a merchant.

COMMISSIONER BYRON: Okay, thank you.

PRESIDING MEMBER PFANNENSTIEL: I have a question about your projections of worldwide demand. You show the demand in China growing, and in fact growing considerably over what it is but it still ends up being a fairly small increment in worldwide demand. Is that because of the coal in China and your assumption is that China will meet its economic growth largely on a coal basis rather than on a natural gas or LNG basis?

MR. JENSEN: It's a very interesting

feature that if you look at the national demands in places like China or India, they anticipate much higher LNG or gas utilization, and by implication LNG, than do the EIA or the IEA. Those international groups are much more skeptical. And I have to say I belong to the skeptical camp because the assumption is that people who haven't been in the business don't understand how complicated it is to do it and that's where the skepticism comes from.

I had an interesting experience earlier this week because Stanford has been running a big project jointly with the Chinese and the Indians and they had a readout in Palo Alto of some joint study work and so I attended that. It was very interesting because listening to the Chinese and the Indians talk, I came away concluding that skepticism was well in order. One of the Indian men from the planning commission said, well if LNG gets down to $4.50 it will take off. And I looked at that and I said, good luck, you know. And I think that's kind of the --

PRESIDING MEMBER PFANNENSTIEL: So the skepticism is not based on the fact that the Chinese will limit coal in any fundamental way.

It is much more on the political dynamics or even the institutional dynamics of trying to commit that much capital to China.

MR. JENSEN: Interestingly enough there have been at least four recent pricing mechanisms going on in Asia. The traditional one which went on for a long time was very inflexible and very stable. The Chinese broke the mold in the late, what, about five years ago with the Guan Dong contract with the Northwest Shelf and the Fujian contract with BP in Tangou.

At that point you had three people eager to put LNG into the market. You had the Northwest Shelf wanting to expand, you had Tangou and Sakhalin II wanting starter contracts, and everybody saw glitters of growing Chinese demand in their eyes and they cut the prices. And there was a real drop off in price.

At that point the Chinese were looking at a sharply cheaper LNG supply relative to coal. And it is still overpriced relative to coal, And they started getting enthusiastic. Now of course, all prices have gone through the roof so that dynamic has changed.

And I must say I think until they decide that they want to limit carbon, and there is no evidence that they are there yet, it seems to me LNG, conservatism about LNG supply demand in China and India is warranted.

PRESIDING MEMBER PFANNENSTIEL: That actually was my next question. In your projections are you assuming kind of a status quo in terms of carbon? Internationally you're not really assuming that either the US or China or India or anybody else makes a major commitment to restricting carbon and therefore looking for some non-coal basis?

MR. JENSEN: Yes, I don't think I've assumed any dramatic change in policy evolution.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Other questions from the dais? Susan.

ADVISOR BROWN: I wish -- Mr. Jensen, thank you for your presentation, that was exceptional and very instructive. Would you comment on global natural gas extraction drilling activity and how that factored into your supply forecast.

MR. JENSEN: Basically the gas business is on a net back basis, it is not on a cost of service basis. Net back basis simply says that however you have determined what market prices are the sellers look to the market for the price and deduct the costs of regasification, tanker transportation and liquefaction to get a net back at the wellhead. And what happens is they decide whether the economics of investment are plus or minus.

And I do not look at costs at the wellhead. There are two big problems when you try to take it back to wellhead costs. The first problem is that most of the world's gas fields today that are used for LNG are rich in gas liquids, often gas condensate.

In many of those cases, and that is true of the North Field and South Pars, the value of the liquids is so good that it would justify flaring the gas to produce the liquids without any question. And I always call that negative opportunity cost gas because nobody will let you flare it, you'd have to reinject it if you had no market for it. So the costs may be negative in effect, that's what I'm saying.

The second problem is that we're in a world in which the tax take, the tax regime of the host government is negotiable and governments are going to decide how much of that they are going to take themselves. And one of the interesting things, you assume when prices go up automatically what happens is that there is a bigger incentive to invest. There is a period of time when the governments decide they have been had and they want to renegotiate terms. I mean, that's what is going on in oil in Venezuela, it's going on in gas in Trinidad, the terms of trade change.

So you've got the tax take, which to the international industry is a real cost, although it is not a true economic cost, and you have got this problem of byproduct credits and liquids. So I stay away from looking at costs directly.

PRESIDING MEMBER PFANNENSTIEL: Other questions here? Questions from the public?

MR. HONG: To follow up on your --

PRESIDING MEMBER PFANNENSTIEL: Excuse me, if you have a question you need to go to the microphone and identify yourself. You need to come up to a dais.

MR. HONG: Hi, I'm Bevin Hong with TransCanada.

MR. JENSEN: Okay.

MR. HONG: To follow-up on your issue on

net backs and how a supplier looks at that. How would they look at the Western United States in that regards in your whole stack of potential places to supply natural gas or LNG?

MR. JENSEN: Well, I mean essentially to the extent that contracts are still being written what is going on worldwide is a transition or evolution of contract terms that hasn't really settled out totally.

In the US what seems to be happening is that for the Atlantic and Gulf Coasts you are beginning to escalate to Henry Hub but you're taking a percentage off of it. In other words you're essentially having a term that is based in some percent of Henry Hub so it's directly escalated. That implies that there is a basis differential relationship.

I don't know how the contracts have been written out here. I think it would be very difficult to do because you in theory want to escalate to what you thought the market was out here but obviously the basis differentials had been variable. I mean, they've gone from plus to substantially minus and they may go back to plus again. So how you write that contract I don't know and I am not close enough to know what the people who are writing them have done, so.

PRESIDING MEMBER PFANNENSTIEL: Thank you. One more.

MR. COWDEN: Hi, Bob Cowden, PG&E.

I see that you have a large growth in Australia in supplies between 2010 and 2015 and I just wanted to get your take. Do you see that supply serving the US West Coast or is most of that supply staying on the Asian-Pacific market?

MR. JENSEN: Well I think what's really happening, of course, is that with the real problems in Indonesia there is a supply shortage out there. What's happened is that Arun, which is in Western Sumatra, it was the Mobil project, arguably the most profitable LNG project the world has ever seen or will ever see, is now running of out gas.

Its in Aceh province where there has been rebellion so the idea of trying to find another gas source to keep the plant alive is not on the table. The Indonesian government has been robbing gas that's supposed to go to the plant for fertilizer to try to keep the locals happy. So Arun, everybody assumes Arun will be shut down in several years.

Bontang in eastern Kaliamantan has a fair amount of gas but the trouble is the gas is owned by one group of people who are later comers. The earlier trains are running off gas and nobody has quite figured out how to put the surpluses offshore together with the stuff onshore. And at the same time Indonesia is taking Bontang gas for fertilizer.

The assumptions -- The Indonesians are basically saying, when their contracts come up for renegotiation, and they are very close to expiration because they were written a long time ago, they are not going to be renewed at the level that they were before. So what you are doing is you are creating a gap that Australia can readily fill as Indonesia drops out. I think that's the game that is being played.

Clearly if a West Coast market develops they would be interested in that as well but at the moment I think the game is much more trying to replace Indonesia and handle growth in the Pacific.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Mr. Jensen. Excellent presentation.

MR. JENSEN: Okay.

MR. TAVARES: Any more questions for Mr. Jensen? Unfortunately he is going to leave before the workshop is over so if you have any questions this is the time. Go ahead, sir.

DR. ARTHUR: Dave Arthur, City of Redding. In your judgment is there more or less or about the same political risk associated with reliance on oil or reliance on LNG?

MR. JENSEN: They're different. One of the interesting things about LNG is that if a project gets done and there is a contract the experience with some big glaring exceptions, the Algerians back in the 1970s, those contracts get honored. I mean, it's a very interesting thing that Indonesia has made contract commitments and is still honoring them even though it is costing them money to buy spot cargoes in the market.

So there are clearly risks there but they're different kinds of risks than oil. I'm not sure I can say which one is more or less risky. You've got to go in with your eyes open.

MR. TAVARES: I saw another hand. Come up to the podium here.

MR. SCHILLER: Steve Schiller with the

University of California.

Following up on Chairman Pfannenstiel's question on China and coal. If I understood your answer correctly you were saying that you are not assuming that China would change how it does its power production. But should China decide to convert more to natural gas as a basis of post-Kyoto treaties, for example, could LNG be a major supply source for that? What would be the issues associated with China using more natural gas for power. Thank you.

MR. JENSEN: Well obviously if they, I mean clearly if China clamps down on carbon it will have a powerful effect on LNG, there is no question about that. But it will also have a powerful effect on the economic price. And I am not talking about politically controlled prices, which China plays a lot with, but the economic price of power.

You cannot generate -- I mean, gas in China is relatively expensive and coal is relatively cheap. If you move from coal to gas you have really jacked up the price, the economic price of power. So I assume there will be some sort of a demand/response to the growth of generation. But clearly it will have an important increase in the demand for LNG.

COMMISSIONER BOYD: Mr. Jensen, to follow-up on that. I've been sitting here agreeing with your conservative view of the Chinese, having spent some time there in the past. Even though they like to brag that their form of government allows them to make instantaneous and quick decisions and move they struggle with infrastructure issues.

And in light of my feeling that that is a big problem with the Chinese and your last response about the ability to jump back and forth between coal and LNG, do you feel even if they made, strangely, a decision to crack down on carbon, which would send a signal that they want to move away from coal, that they could really respond very rapidly to accomplish that? I mean, they do wonderful things sometimes but sometimes they stumble all over themselves.

MR. JENSEN: I guess my observation of China is that it is an economy in transition from command and control to market. And in with its command and control hat on it can do things that are unbelievable. I mean, the Three Gorges Dam, the pipeline, the West-East Pipeline that links the Tarim Basin in the west with Shanghai.

I have a little graph I show and down in the corner is a little scale showing the various Asian pipelines. It's a scale from New York to San Francisco and I say, we never built anything like that in the US. But the problem is, once you build it and you really are trying to sell it in a market economy they have trouble essentially selling it and moving it into the market.

On top of that there are some tensions that I don't completely understand between regional governments and the national government. And what the national government wants to do sometimes the regional governments do not obey. So it's a very complicated thing in order to change policy and see what the results were.

COMMISSIONER BOYD: Like many parts of the world there is still this tribalism that rises up in governments on occasion. Thank you.

MR. TAVARES: Any last questions? No takers?

Okay, next we have Mr. Dale Nesbitt. He is actually one of the developers of the North American Regional Model. He is going to make a presentation on the key assumptions of the model that we used to develop the reference case. So Dale.

DR. NESBITT: I appreciate the opportunity to be here. We have just moved from PowerPoint to .pdf, sorry about that. I think it will work fine. If it doesn't we'll be, we'll be shifting around.

I do want to say, as usual Jim has made a great presentation. Articulated the issues quite nicely. A lot of the world dimensions that I had to say I won't have to say because I think Jim has covered those very well. I'll add my two bits worth in where appropriate and where important, particularly on West Coast and emerging West Coast markets for LNG and world contracts.

But my job today is to talk a little bit about the assumptions and the realities really of North American natural gas markets, world natural gas markets, North American power markets, North American tradeable emissions markets and how they have been incorporated into the set of assumptions that we have used to craft a reference case in the four scenarios that we have here.

It works pretty well. Here are the

topics. I want to talk just a little bit about North American natural gas supply. It's a critical issue. We have been talking about LNG. But even in the high LNG cases at least two-thirds of our supply is buried in the turf of North America. We have got to understand that and we have got to put forth some assumptions that are reasonable there.

I want to talk a little bit about LNG and world gas trade.

I want to talk a little bit, actually quite a bit about industrial demand for natural gas and power in North America and how we have represented that.

Talk a lot about emissions allowances, trade, the environment and the effects on natural gas and power. This is a very much under-appreciated and under-quantified phenomena. We'll tell you the assumptions that we have made here.

And then finally talk a bit about the fuel burn for power generation in North America. Where is that now and where is it going?

The North American gas supply. I know the Commissioners were very involved with the NPC at least in a review mode. The NPC, alas and a lack, is still the most current assessment of the North American resource base that anybody has.

What they did in the circa 2002-2003 time frame was they assessed each and every one of the 950 plays from the Chukchi Sea to the Burgos Basin. And they did that by saying, let's come up with a field, size and depth distribution. Let's look at the deposition in the ground and then let's superimpose an assessment of finding and development cost across the top of that to try to get our hands around some notion of what's down in the turf and how much does it cost to get it out and how fast can you get it out. And how much land access might you need to get it out.

It is very important to set that background because the set of assumptions that are used in the reference case are an update and an extension of that assessment.

It is very interesting. Many people in this business have said, well, you know, those numbers lead to low gas prices in everybody's model, including the EIA's, those assessments are too optimistic. Let's chat about why that's the case and what we have done to render those more realistic.

Those superseded assessments that were made, if you can believe it, in the early '90s. And those assessments were based on cost estimates from the late '90s and the early '00s. What was the price of oil in 1998? Eight bucks. What was the price of natural gas in 1998? About $1.80. What were the costs, the production cost estimates then? They were low, much lower than today.

And I think Jim has articulated quite nicely that commodity prices are off the charts today. They are at unprecedentedly high levels. Steel historically is a nickel a pound, now it's 15 cents a pound. I grew up in the copper business. I grew up in a copper mining town and I can remember when copper price was 50 cents. Do you know what it is today? Three bucks. All commodities including oil and gas are very high.

So the issue is, how does this impact F&D costs. We have made a set of assumptions to try to incorporate these institutionally higher commodity prices including but not limited to engineering services into these estimates.

Okay, I'll let you read that. Now the adjustments that we have made to these to craft the base case here. If you go back and look at the NPC's assessment work -- And I would commend NPC. It's still on their website, www.npc.org. You can look at all 950 plays. You'll sleep very well if you take that 479 page report and start it about ten p.m., you'll be asleep by 10:15. But it's got very good estimates in it.

One of the things that those guys did, and being self-critical of their own work they said, we had too many big fields in there, which means we had too much low cost gas.

So what we have done to create this base case is to remove a number of the very large fields and insert those back as small fields. And I think the domestic industry realizes that the size of fields that we have been encountering and prospectively will encounter in the coming five, ten, fifteen years are tiny, very tiny by world standards. And certainly very tiny by historical standards.

And the way to think about F&D costs, finding and development costs, is you divide the $10 million whole by however many Bcf are down in the ground. That gives you the incremental cost. So if that Bcf down in the ground drops your incremental domestic cost goes up pretty much pro rata.

Okay. And particularly in being self-critical of their work they were very critical of their own work in the Midcontinent and in the Rocky Mountains so those have been adjusted.

There has been some substantial adjustments due to the pessimism that has been encountered in onshore and Texas and onshore Louisiana. The field size and depth distributions have been reduced.

The key finding of the NPC, and I think it is very believed and understood around the industry is, there are volumes here in North America but they are encapsulated in very much smaller fields than we thought. A six Bcf field used to be a dry hole, now it's a monster. We're down in the one to one-half Bcf per well level. Which means our finding and development costs not being $1.80 anymore are more like $4.80. So that has been incorporated into the base case.

We have assumed, and it is certainly subject to alternative assumptions, that all of the gas that we have assessed here is quote/ unquote in play. Which means that ultimately, perhaps with some temporal lag, we are able get access to the entire domestic resource base with two exceptions, offshore Atlantic and offshore California. And the assumption that has been made in the reference case is those will be permanently off-limits to exploration and production.

This is a fairly bullish assumption on the availability of domestic gas to market. The NPC itself said that perhaps 40 percent of the resource basin in the Rocky Mountains will ultimately be off limits to E&P. Certainly the experience we have seen in recent years suggests that that is not an unrealistic number.

But I would commend us to think that we would have to make an assumption to keep that off limits. That it would be off limits forever, not just a few years.

We didn't feel like that would be a good base case. We felt like it might be a good sensitivity case to start restricting availability of domestic tracts of land to E&P. So it's a fairly bullish assumption.

De facto what this base case assumes is that all of the domestic resource base is accessible when and if it is economically competitive. That's a fairly bullish assumption embedded in the reference case and there's sensitivity cases to examine the what-ifs.

Questions about the domestic resource base assumptions that are in the reference case?

ASSOCIATE MEMBER GEESMAN: How did you, how did you determine how much to downscale your megafield assumptions?

DR. NESBITT: Well we're spending quite a bit of time working with people in the industry and looking at discovery sequences that happened in the previous few years. What we did was fairly simple. We took the very largest fields down to about two Tcf, which is considered a monster field now. We've chopped those into categories of smaller field sizes, which de facto raises their production costs. So it was judgmental based on our knowledge and experience in the industry.

The US Geologic Survey has not reassessed those basins, private industry has. We're party to some of those things. But the answer to your question is it's really judgmental.

ASSOCIATE MEMBER GEESMAN: Then is it your judgment that the earlier geological assumptions were wrong or that the earlier economic assumptions were wrong?

DR. NESBITT: Both. But the geologic assumptions. That's really a good question and right on point. The assumptions in the Anadarko Basin and the Rockies Basin is that the geologic assumptions were wrong. They just weren't -- there just isn't statistically an 11 Tcf field in the deep Anadarko Basin.

And the information that has emerged there is we have shown a lot more seismics out there. We've looked in the ground more and we don't see the formations that we saw back from the 1998 to 2002 time frame when the NPC work was done. Dittos for the Rockies. So the experience has not shown both seismically and E&P the existence of these large fields. So I would argue that that's a geological shortcoming or geological learning.

The other one though, the other half of our question is true too. That when we looked at the original assessments that were done by the NPC those were done in '03 and they were based on roughly five years of previous finding and development statistics.

By happenstance that was a fairly low but increasing point in time in E&P costs. It had low steel prices, very low; low copper prices, very low. There was surfeitive construction in F&D resources around the world. So the thought is that the economics were a bit optimistic across that period vis-…-vis the long term.

So the answer to your question is both.

ASSOCIATE MEMBER GEESMAN: So then when you assume a 100 percent accessibility of what gas you believe to be there, and your timing I believe was said was based on the economics.

DR. NESBITT: Yes.

ASSOCIATE MEMBER GEESMAN: Where is the larger vulnerability in that new assumption? Is it geologic or is it economic?

DR. NESBITT: Good question. I think -- My own view is if you assume, let's take the simple assumption that the NPC articulated as an alternative that 40 percent of the gas in the Rocky Mountains is held on BLM land and may well never be accessed. I don't really care what the cost is. That's a volumetric, geologic issue. Now there may be natural gas in Yellowstone National Park but who cares.

So I would argue that's a volumetric issue. And it is the target, I think, for some --

I know the industry worries about that a lot, for some careful rethinking of scenarios that we might want to run. Because I think implicit in your remarks is, so what if we don't have that. So what if you're wrong, Dale, what does that do to the gas price? It drives it up. Forty percent of the volume gone, you get it drives it up. Was that the question?

ASSOCIATE MEMBER GEESMAN: It was.

DR. NESBITT: One other point about the domestic resource base. What sets the price of natural gas for the next 30 years? Is LNG ever going to be in for marginal? No. The price of natural gas in North America is set by bad rock in North America. So it really matters, that's why I put it number one. What is the marginal cost of exploration and production from the very terrible rock that comprises North America by world standards, the leading term.

LNG and world gas trade. One of the things that we did this time is we didn't want a stand alone North American model. NARG is not enough, NARG is gone. What you need is a fully interconnected model of each and every region of the world so that you don't have to guess in the blue, and this is what we tried to do in this base case.

So what is the price and cost of LNG coming onshore at Baja California? So what is the price and cost at Bradwood Landing or Skipanon or Tansy Point or Woodside or Cabrillo? We don't want to guess, we want a model. And so in your base case we did that. And that blue, that blue curve is important. I am going to give you a few insights from that that complement, hopefully don't refute what Jim said but they may in a few cases.

What we have done is to explicitly calculate the cost and price of LNG at every existing and prospective landing point in the world so that we are not guessing, at least that is our objective, what the price is of LNG, net back if you will, landed at Costa Azul. Landed at Cabrillo, landed at Woodside, landed at Tansy, et cetera, et cetera. We want to know that.

We also want to know that in the Gulf of Mexico, because there is intercourse between the Gulf of Mexico and California, it's by displacement. Yes it is a vulcanized market to a degree but we have common resources that serve the

Chicago market. And if you displace West Coast gas out of the Chicago market what happens to West Coast gas? The price goes down, westerners benefit. You have to know it all.

The model we've used has been around for awhile. It takes the North American piece in red and it hooks it up to the world in very much the way that Jim said, okay.

A little bit on the data. You might ask me about data, you asked Jim about data. It is very, very important to look at the LNG sources around the world and ask the question, how much volume at what cost is out there in the world on or near the waterfronts of the world. And the answer is it is infinity minus a little bit.

What is the cost of it? It's zero plus epsilon, where epsilon is mighty small. Jim articulated it right. Most of that gas near the water is pumping condensate at $60 a barrel oil. It makes so much money there's not enough pillowcases to stick it into. So the direct marginal cost of gas all over the Persian Gulf is negative. Jim is absolutely right.

The issue is the infrastructure. The liquefaction facility, the boats, the regasification facilities that get it out.

So we have assessed every assessment unit in the world and they are in your model, you can go look at those. It was done in collaboration with the United States Geologic Survey. I would comment to you their World Energy Program is on their website. You can read about every single producing basin in the world and know how much gas, oil and liquids are in the ground. It's great reading.

The demand in every country in the world has been put into the base case. I assign a lot of credibility to the IEA. And in answer to your question about China and India, the IEA is very, very, in fact surprisingly bearish on India and China ever importing LNG. They don't want to spend the hard currency.

The one thing about China that people don't realize is their per capita GNP is very, very low because they have got a lot of capita. Capital is a short device over there and they are not going to spend capital on LNG if they can spend it on coal. This is the IEA's view. I happen to subscribe to that view.

ASSOCIATE MEMBER GEESMAN: What's the --

DR. NESBITT: Every pipeline, existing and prospective in the world and every LNG liquefaction train, existing and prospective in the world, is in your base case. You can look at those.

ASSOCIATE MEMBER GEESMAN: What is the vintage of the USGS assumptions?

DR. NESBITT: The World Energy Program? The original publication was 2000. And what they put together on their website is a four-CD set dated 2000. Every year they have a conference and they update. If you asked me the specific regions that they have updated I don't know, but they've updated a tenth of the world in each year. So they have updated a tenth of the world, if you will, in each of the subsequent seven years and added regions like the Nile River Delta. So it's ongoing.

ASSOCIATE MEMBER GEESMAN: So they have stayed more up to date than they have with the North American resources?

DR. NESBITT: Yes they have. That's a really good question. Their last North American Assessment was in 1995. Absolutely, absolutely a good question.

ASSOCIATE MEMBER GEESMAN: Do you feel that they are entitled to a greater presumption of reliability than they have been in North America?

DR. NESBITT: I do, yeah, if you've been. And you can get to their conference, it's held every October in Denver, and kind of listen and see what degree of currency they have. They have a huge amount of funding from government agencies that we don't talk about because those government agencies that we don't talk about want to know how these governments that we don't talk about are going to develop their gas, oil and liquids resources.

So the aroma, if you will, of the assessment is there is a lot more money being put into it. As you probably know the USGS is line-itemed in the Congressional budget and their domestic program, I know this is hard to believe, is the subject of politics on the hill. I know how hard that is to believe. So they get squeezed for funding on the domestic resource base.

COMMISSIONER BOYD: I join Commissioner Geesman in perhaps a little skepticism because I still can remember sitting here, maybe even in this chair in 2003, when we had kind of a world oil/gas conference in this room and the USGS was so bullish on North American supplies. I mean, the world is not at all today as they described it to us.

DR. NESBITT: That's exactly right, Commissioner Boyd. I think what they would say to you and what I have observed, and I certainly don't speak for them, is that as they sat here in '03 they realized the most recent assessment they had to draw on was published in 1995 and was actually done in the five years previous to that. And I think if you brought Don Gautier in there he'd say yeah, we're 15 years old. I agree with you.

Okay, what do we get out of this model? Everybody please raise your right hand and repeat after me, LNG price is not coupled with oil price. It's not. I was in Egypt about three weeks ago, we were trying to negotiate an LNG deal. The minister of Egypt looked at me -- Well I'll tell you the story.

My client said, who is trying to get an LNG liquefaction deal with the Egyptians, he said, if the minister asks you a question about price, Dr. Nesbitt, don't answer. Just don't say a word about price, we don't want to go there. We just want to make sure their LNG comes to Texas.

So I walked in the door and the minister looked at me and said, Dr. Nesbitt, how come the price in Zeebrugge is 3.50 and the price at Henry is 7.50? I looked over at my client and I said well. He said, answer him. It's because it's always going to be that way, that's why. It's because Jim had it right.

Europe is at the confluence of more gas than you can think about. That 85 percent of the world's gas that is on a line north from the Strait of Hormuz to the North Pole is near Europe, it is not near North America. And to get any of that gas the European price is going to be soft.

Another little fact about Europe, it's only about five-eighths to two-thirds as big as North America, Europe is not that big. They've got more folks than we do but they don't burn more gas than we do. So it is very important to think about that.

Now the other thing, $3.50 and $7.50. What is the price of oil in BTUs today? Ten. Now where I grew up $3.50 is not equal to $10 and $7.50 is not equal to $10. Maybe that reflects on where I grew up but that is just -- the oil and gas prices are not coupled. They are not coupled. They may be correlated but they are not the same. They are not the same commodity, they don't have the same use. Very important.

The other thing about LNG contracts. He also asked me, the minister said, I heard kind of a funny story about the French. About two weeks ago, this was about three weeks ago, I heard what the French did is they took a delivery from the Algerians under contract. Put it in a cryogenic tank. As soon as the Algerian boat was over the horizon they put it on another boat and sold it in North America. They broke the contract. They didn't keep the gas, they sold it.

And if you go to a place like Poten & Partners today that rings a bell, they've got a big bell sitting on the trading floor. Every time a spot cargo trades they ring the bell, you can't even have a conference, the bell is ringing all the time. LNG is not following the contracts, LNG is following the market. Very, very interesting. Now I don't know what that means but certainly in the base case that we have done for the Commission we've assumed that LNG is fully arbitragable.

That's an aggressive assumption about price but that is what has been assumed.

One of the other insights that you have is that North America is the big dog. North America is 25 Tcf, Europe is only about 15. The price is going to be firm in North America. It will attract these cargoes, particularly on the East Coast. And I won't make more any remarks about that, I think Jim was quite right in his remarks there.

So we wanted to understand these and to interleave them on your considerations of North America. If you want to ask me any questions about that later I'm glad to field those.

Number three, industrial demand in the United States. Questions abut LNG? Okay, Industrial demand in the United States. One of the big issues in industrial demand in the United States, if you have gone to the DOE hearings on the energy bill which I went to, two days long. A day and three quarters is the gas users complaining the price is too high and they're leaving North America. They don't want to hear substance. Just all the fertilizer manufacturers and everybody else. And it's absolutely right, they can't live in a $7.50 world.

So what happened was Dr. Ken Medlock of Rice during the NPC and later under the sponsorship of the CEC decided he would try to build a statistical model of demand that included lags, own price, that's gas price, oil price, income and the weather. He did that and he found out that the leading term in gas demand is gas price.

And then the Commission hired Dr. Medlock to build the demand functions for the model that you use and those are the models that are in there, the demand functions that are in there. They presage quite low industrial demand in North America by EIA standards, quite low. Because at the prices you're projecting, according to the historical record the gas demand in North America in the industrial sector simply won't be there. The industry simply won't be there.

And that's very important. Somebody will ask, why isn't the EIA publishing that? If you're the EIA every one of the 535 guys on the Hill comes down and says they want high gas demand in their region because they don't want to see projections of their region engaged in economic disability or debilitation. And so your institutionally forced to put forth a high demand projection for industry.

You don't have that. You have what you hired Dr. Medlock to do, which was put together gas demand projections that are consistent with the historical record. And that's done in the WECC, it's not done in the rest of the country. So that's important. We'll go beyond that. You have a fairly modest here projection of industrial gas consumption. We're going to see where the high side here is in a minute.

Questions about industry? What's in your base case? Okay.

Environment/tradable emissions, blah, blah, blah. Very quickly. Good old days, electricity was an intensely local business. PG&E could do their own business, Edison could do their own business. They owned all their plants, they didn't have to talk to nobody about nothing, if you will. Not anymore. Because what we now have is we have for SOx we have a nationally traded emissions market which connects us up to Epsilon, it connects us up to AEP. So we have to bid for SOx credits nationwide.

NOx, the NOx laws are about to change. We have the SIPCALL states that are seasonal only. In 2009, 2010 we're going to go to year-round. Everybody is going to have to elect their way. California has some grandfathering. But these laws are getting tough. Mercury is going to start. Mercury starts at 48 tons. It's going to 15 tons very quickly. And under almost any of the bills we see on the Hill CO2 trading is going to start. McCain-Lieberman, Binghamon, Feinstein. Different caps, different trades.

Now what that means is that power is not a local issue anymore. It also means if we look at all four of those things, SOx, NOx, Mercury and CO2, which fuel gets hit by each and every one of those? Coal. Coal. These things have already cut into the fat on coal and they're cutting into the meat now. So it's very important, okay.

What we have put into your base case for natural gas burn outside the WECC -- inside the WECC I'll tell you what we did but outside the WECC is our integrated supply demand run in the power sector connected with these tradable emissions allowances so that we have a view of gas burn outside the WECC that is more consistent with the way these traded emissions allowances in the environmental business are driving the system.

Now people will tell you, yeah, yeah, yeah, I get it, I get it. What that means is that nobody is going to build a new coal plant. That's right. But if we have tradable emissions allowances in carbon what else is going to happen? You ain't going to run the coal plants you got. It affects the operation of the system as well as the implementation of a new system.

And to give yourself one quick piece of evidence on that. Think what happened in Europe 18 months ago. Are you aware of what happened in Europe when they were trading carbon? What happened? The carbon price got to what? Thirty bucks, 30 bucks a ton.

What was the leading thing that happened in Germany when that happened? The coal plants stopped running at time of base because that's the only way you can meet the cap. You can't afford emissions allowances for 8,760 hours a year. You're not going to roll them out at time of peak or you'll have a shortage but you'll roll them out at time of base.

What happens when you roll them out at

time of base? You used to burn coal and now you burn? Gas. It stimulated gas demand off the charts. So it's very interesting.

In the base case that we have crafted here for you we have run this model and we have put the gas burn outside the WECC from this model into it. Inside the WECC we have used the statistical studies that were done by the CEC staff and Dr. Medlock. So the reference case embeds the CEC power burn forecast within the WECC and these burns from this integrated model outside the WECC.

Okay, one of the really --

ASSOCIATE MEMBER GEESMAN: How consistent are the two?

DR. NESBITT: They're not.

ASSOCIATE MEMBER GEESMAN: It would seem there's a pretty large dichotomy there, isn't there?

DR. NESBITT: I don't think so. But I think it was very -- it's very important. I think what we should do, if I were the benevolent dictator I would in the electric sector, this is my personal view, use the integrated solution inside and outside the WECC. I would use the

Medlock demand functions for all sectors other than the electric sector. That's if I were the benevolent dictator.

But there is an inconsistency, I agree, Commissioner Geesman. I don't think it's a fatal inconsistency but you're aware of what you've got there.

Now here is an interesting little issue. If the Binghamon level cap in trade came in, the Binghamon level cap in trade comes in, everybody thinks that pretty tepid. And there were no safety valve. In other words the carbon price was going to float so that you'd hit the cap, how high would that carbon price get? How high would it have to get before we could hit the carbon cap? That's a darn good question, isn't it?

Our numbers suggest, everybody hang on to the arms of your chair, 50 bucks a ton. That's what it takes to hit even the Binghamon cap. It really stimulates the gas. This is not a trivial issue.

So this is the system that you use to generate the outside WECC portions of your base case.

Last slide. The gas burn outside the

WECC is pretty strong in these cases, in your base case, and it is because they're reflecting the SOx, NOx, mercury, and I'll call it the tepid or the fairly benign Binghamon safety valve on carbon, seven bucks a ton.

That's it. Questions, comments? How did I do on time?

PRESIDING MEMBER PFANNENSTIEL: Questions?

MR. TAVARES: I see one hand. Get close to the microphone and identify yourself.

MR. SWEENEY: Yes. My name is Mark Sweeney, I am a consultant working with the California Natural Gas Vehicle Coalition. Dale, I have a question about assumptions.

Before the workshop back in March a document was put out listing the inputs and assumptions for NARG and the first one listed was the alternate or substitute fuel price forecast, which is a forecast of crude oil prices.

And the document indicates that for the 2005 natural gas assessment report the EIA high oil price case was used as a reference point on all prices for the natural gas price forecast. It also said that the plan was to use the high oil price from the 2007 annual energy outlook in developing the natural gas price forecast in this effort.

The actual draft report though says that the reference case oil price was what was used in developing the forecast. So I want to clarify which oil price forecast was used in developing the model results. And then I have a follow-up question.

DR. NESBITT: It was the reference price. But I want to share one insight with you. And that is, are you ready for this, gas and oil really don't interact in North America anymore. You know why? No refiner produces heavy oil anymore. There is no linkage between gas and oil in North America. We used the reference.

MR. SWEENEY: I agree with that but I think you would agree that there is some impact on the natural gas price forecast as a function of the assumed crude oil price, however small that may be. I guess --

And just so everybody understands that the high oil price case that EIA has prepared and that the CEC uses calls for oil prices to go to $100 a barrel in 2030. The reference case

forecast suggests that oil prices in constant
dollars will go to $60 in 2030, and that's a
difference of $40 a barrel.
And what I am trying to understand is,
is there any reason why someone would assume that
a more optimistic outlook on oil prices that was
made two months ago was appropriate two months ago
or two years ago, now? Is there any reason why
one would have a more optimistic outlook for oil
prices to the extent of $40 a barrel in 2030?
DR. NESBITT: Is the question, let me
reframe the question to make sure we get it. Are
you suggesting that $100 a barrel might be a more
reasonable assumption and that by assuming $60 it
is more kind of optimistic or less realistic?
MR. SWEENEY: Well, it's a whole lot
more optimistic and it's a whole lot more
optimistic than the assumption that was described
in March that you were going to use. And it is
certainly a lot more optimistic than the
assumption that was made two years ago.
MR. FORE: Well, we used the reference
case.
MR. TAVARES: Identify yourself.
MR. FORE: I'm Jim Fore with the CEC.

We used the reference case forecast from the 2007 annual energy outlook, really to match with the fields group int he oil. They were using that sort of as their base, they told us.

We did do sensitivities that used the higher oil price in order to see the impact that it would have in the gas market and they will be covered later this afternoon. That was one of the sensitivities we ran was to use a high oil price and a low oil price to see how it impacted gas. And so we will be covering that as part of this workshop. That is one of the things on the table. Is that the right oil price to put in or should we use a different one. But we went with the reference case from the EIA as our starting point.

MR. SWEENEY: A $40 a barrel lower oil price forecast level than what was deemed to be an appropriate assumption two months ago?

MR. FORE: I don't think we committed completely to what we were going to use. We were just going to use the EIA forecast. We did the sensitivity to it and the sensitivity showed that it didn't make much change in the gas demand because it doesn't influence the industrial demand that much.

And part of the rationale on that is that we felt a lot of the industries that had, that used a lot of gas had moved out. And so even though you have the high oil price there is no industry to switch back to the gas because they have already left and went to areas where they could get cheaper gas, such as the fertilizer industry and heavy users of gas.

MR. SWEENEY: My real issue is whether or not the oil price forecast is realistic or most likely to have an predictive validity. Let me just say that the Commission has consistently relied in the past on the EIA's oil price forecast and those forecasts for a long period of time have vastly underestimated the actual level of oil prices.

And even in the high oil price case we went back and looked at the annual energy outlook forecast going back ten years and looked at the predicted crude oil price in 2005 from those forecasts. And basically the actual crude oil price in 2005 was almost double what it had been forecast in the high oil case.

So I'm just wondering why the Commission seems to have this commitment to going with a reference case forecast when every evidence from the marketplace would support the credibility of the high oil price case. And that is just a comment.

MR. FORE: Well you know, I got laid off in the oil industry when they thought it was going to $100 and it went down to $20 so these forecasts do vary a lot and I'll admit that. So what we have chosen is one we think that is somewhat realistic. And it may be low or it may be high and then we run the sensitivities to see if it is something that we really need to look at.

And what we're finding is that the high oil price is not impacting our gas demand that greatly. So, you know, it's something that we look at but we don't feel it is a significant part in changing the forecast outlook and what we would forecast to be the gas demand.

MR. SWEENEY: Well one last comment on the oil price forecast. That at the May 8 workshop on the transportation fuels price forecast the staff basically presented three forecasts, a reference case, a high case and a low price case without making any indication of what they thought was the most likely. And it would appear from looking at what was presented that they think the low price forecast is equally likely to occur as a reference or the high oil price case.

And I think at some point the Commission has to make a policy judgment on the outlook for oil prices. To say it is going to be between $30 and $100 is too broad a range to rely on in making the kind of policy judgments that the Commission needs to make, especially in the AB 1007 proceeding. Thank you.

COMMISSIONER BOYD: A couple comments I would make. I think the dialogue we just heard just reinforces the statement that was made that we struggle as an agency to convince ourselves and to affirm the fact that gas prices and oil prices are truly not connected. And I think you have heard today that is becoming more and more true.

And I think it is a little strong to say that we are dedicated to the EIA and their forecasts. Commissioner Geesman and I and all the staff went through lots of agony in the 2005 Integrated Energy Policy Report struggling with that premise and trying to decouple ourselves because of the fact that they were more wrong than right.

And I think the purpose of public hearings and workshops and ranges is to hear the kind of input you provided, to kind of get some dialogue going on high, low and medium and to make decisions. And I think we made a quantum change in 2005 as a result of lots of public discussion like this and upped, upped the view that we took. Not that we were right but who was. But we're trying to move in that direction and I appreciate the comments you've made.

ASSOCIATE MEMBER GEESMAN: I also think that in terms of the policy recommendations that the state ends up making or embracing, you want to look across the range of forecasts and attempt to develop policies that are robust across that range and that have some feel for which case in being wrong presents the greatest level of risk to you.

I think you're searching for as risk-adverse a set of policies as you can economically justify. I think at least from the state's perspective you want to step back a bit from feeling that you need to have an accurate prediction of prices going forward.

Our history I think induces a pretty

high level of humility about the accuracy of our price predictions. At the same time I'm confident, and I think historically we have put together a bundle of policy recommendations that attempt to minimize risk if our forecasts are wrong. And more often than not I think that the risk of our forecast being too low probably creates quite a bit more risk to the state than the constituencies that we're supposed to pay attention to, than our forecast being too low.

DR. NESBITT: Along those lines I think that I agree with that. Let me commend to you this document if you haven't seen it. I think it's fairly new from the EIA, it's terrific. It's called Annual Energy Outlook Retrospective Review, Evaluation of Projections in Past Editions, 1982 to 2006. Nobody can see this but blue means they were too low and green means they were too high. Everything is blue or green.

All the forecasts -- And it's not right, Mark. All the forecasts that were made before about 1998, the oil price was always lower. The federal government was always forecasting too high on oil price and the price was always below. The worm turned in about 1995. The oil price was always higher. What does that tell you? It tells you the federal government always forecasts today's price. Because it is too hard politically for them to forecast changes in the system.

So what it tells you, and I am very cynical, I never calibrate to the EIA. I don't. And I think to the CEC's credit, you guys have done independent analysis here that just doesn't accept the EIA. The EIA is an intensely political body, intensely political body.

You have done independent work and you have taken the heat for it and I think that is very commendable, you know, in the interest of getting good, solid -- and I couldn't agree more, robust answers from the prospective of hedging rate payer and business risks for the people in the state, absolutely.

PRESIDING MEMBER PFANNENSTIEL: Go ahead. If you have a question go up to the podium.

MR. SWEENEY: I just have a follow-up comment. Dale, you know, I am not defending the EIA's forecast. I guess what I'm defending would be a more pessimistic outlook for the future level of oil prices than a more optimistic outlook.

But basically the California Energy Commission has relied entirely on the EIA's crude oil price forecast going as far back as I can tell for its forecast of crude oil prices and for its forecast of petroleum product prices.

And you look at a situation like AB 1007 where the policy objective is to reduce petroleum dependance by displacing petroleum use with alternate transportation fuels. Basically if you adopt an unrealistically low forecast of gasoline and diesel prices then you underestimate the economic cost of continued dependance on petroleum and you also underestimate the net benefits that result from the displacement of petroleum by alternate transportation fuels.

And I agree with what Commissioner Geesman said about it is important to be aware of the range of possibilities because the uncertainty is substantial. But ultimately I think people have to make a judgment about what they think the most likely outcome is recognizing that there is lot of uncertainty around that.

So from my vantage point simply recognizing the uncertainty doesn't get you to the point you need to go to, which is a point of having, based on what we know, all the information, what is the most likely expected outcome, recognizing that that very likely will wrong. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Another question?

DR. ARTHUR: Dave Arthur, City of Redding. As I've listened to your presentation and the one previously it seems like a certain theme is emerging and that is that supply continues to turn out to be less than what we had previously anticipated for a variety of reasons and demand seems to be increasing above what we maybe thought it was going to be, again for a variety of reasons. Is that a correct assessment of what we have heard and do you see that continuing into the future?

MR. TAVARES: We're going to have a discussion on supply and demand in the next few -- actually in the morning we're going to have discussion on demand and then supply this afternoon. Also we're going to have additional discussion on the uncertainty of the different variables, including oil, that we have. But we will have an anticipated comment here from Catie

Elder, she is from RW Beck and Associates.

DR. ARTHUR: Then I have one other question if we're not going to address that. And that was that it was stated that the price of natural gas in Texas was in the neighborhood of $7.50 and the price in Europe was in the neighborhood of $3.50 I believe. Do you see that kind of spread persisting where the size of the spread exceeds the transportation cost of moving the fuel itself?

DR. NESBITT: I think I'm going to speak for Jim. I think we'd agree, yeah. I think one of the things that Jim stated quite accurately was the shortage of liquid fuel supply, liquefaction around the world. That shortage I believe is temporary but we can fight how long it is.

As long as there is a temporary shortage there's going to be people fighting over that supply and basis differentials will not necessarily equilibrate to interregional transportation costs, absolutely.

We saw that in the winter of '05-06 where Europe had a 30 degree cold winter and we had a 100 degree warm winter. The cargoes were sucked into Europe. Last year the Japanese had a high demand, there were supply problems in Indonesia and cargoes were sucked off the Atlantic Rim into Japan.

So I do, I don't know Jim if you'd agree, I do see continued what Jim called instability I think quite correctly in these world LNG markets where price differentials exceed transportation costs for some period of time. Would you agree with that, Jim?

MR. JENSEN (FROM THE AUDIENCE): Sure.

MR. TAVARES: Okay, Catie is going to make a comment.

MS. ELDER: Of course, behind a screen nobody can see me, I realize. I'll try to stand up taller. But for those of you, I'm batting cleanup at the end of the day.

And some of the questions that Mr. Sweeney in particular asked are addressed in the presentation that's labeled Alternatives to Consider Uncertainty Around Staff's NARG results. And there is some analysis in there about the links between, or the lack of links between gas and oil prices. So if you can hang on until the afternoon I promise there will be more entertainment.

MR. TAVARES: Okay, thank you. Any more questions for Dale?

ASSOCIATE MEMBER GEESMAN: Is the afternoon the more appropriate time to ask questions about particular infrastructure?

MR. TAVARES: Yes.

ASSOCIATE MEMBER GEESMAN: Okay. And is Dale still going to be around then?

DR. NESBITT: I'll be here as long as you need me.

ASSOCIATE MEMBER GEESMAN: Good.

MR. TAVARES: Yes, he's chained to his chair right here. (Laughter) Thank you, Dale.

Next we have Jim Fore. He's going to start our discussion on the results that we have on the reference case and he will address demand. Jim.

MR. FORE: Thank you, good morning.

In addressing demand I want to take kind of the first part of the presentation talking about how we put the demand forecast together and some of the main assumptions in it and not so much about the numbers that we get out at this particular time, since we want to determine if we have looked at the demand sector properly and allow everyone to understand how we came about developing the forecast that we have.

Our demand sector is divided into the Core sector, which is really the Industrial (sic) and Commercial sector. And we use that basically because these are sectors in which people cannot switch fuels. The Core sector could include some of the industrial demand if they are not able to switch the fuels.

The Industrial sector is normally referred to as the non-core and this is people that have the ability to switch between oil and gas. Although it is getting less there's still people that have that ability. In the West we have it broken down between Chemical and Non-Chemical.

In the East we just have an Industrial sector, just one sector. And in the East we use just Core instead of breaking it out by Residential and Commercial.

We have certain sectors that have a big demand of gas that are outside of this. In California the natural gas used in the enhanced oil recovery is a major demand of gas and so we have that broken down separately. For Alberta the

Oil Sands project basically accounts for about half of their demand for gas in that province so we have it broken out separately.

And then the power gen we get from CEC's forecasts for the WECC area. And as Dale said, we used his model in order to get the electricity fuel burn in the East. Now this forecast comes from our work, this comes from Alberta, this comes from a combination of CEC and the Altos people. This comes, part of it, from the WECC.

So it's all based on some elasticity functions that were developed by Dr. Medlock that we actually talked about in the last EIA -- IEPR report. We used it then. We updated them with the latest part of the historical data, recalculated the demand and that's what goes into the model.

Let me indicate how we use this in the model. What we do is we take the last year of historical data and we take the parameters that we have determined to be key for the demand sectors. And we take that and we put it in.

Now this is the areas where we have the inelastic as I told you. We get this from California, we get this from our report. We get this from the electricity people. This is a combination of looking at the oil production in the state and the amount of gas used. We get this from Alberta. This is the export of LNG to Japan.

This is fixed so we treat it as an inelastic because we don't see that expanding. Which is not to say that we don't consider price or things other than just these numbers but we do it through an process where may we go back and forth between these when we do our calculations.

In the elastic side we have the residential, the commercial, the industrial, and we have it broken down into the two sectors here. And then the power gen outside of the West we go back and forth between our gas forecast and we can go back into the NARG with the electric forecast from Altos. And go back and forth to do that in order to adjust it over time.

Okay, for the residential/commercial sector we found that gas price, gross domestic product, heating degree days, population, and we have a residual factor in this. We started out with what we call a shadow price. We use a gross domestic product of around three percent.

We have heating degrees days, that's

based on a 15 year average for each one of the states. For Canada we didn't have good data so we used the heating degree days for the states that border the provinces in Canada and put that in. We used a population forecast from the Census Bureau for the US and from Canada we used their forecast. For California we used the one from the Department of Finance. We then calculate a demand for these sectors by states and put them into the model over the forecast period.

We go through the same process for the industrial sector where we use the industrial production index, the natural gas price and the crude oil price, which is the EIA price in order to account for substitution, and there is a residual factor. And we put this as the original forecast into the model.

This is just an idea of the elasticity values that we had. We know that they are performing as you would expect on an economic point of view. The higher gas price reduces the demand for gas. Greater GDP increases the demand for gas. Greater industrial production would increase the demand for gas.

Heating degree days most critical in the residential sector, not so much in the commercial sector. And then we have the population as a big driver in the residential area, whereas domestic production in the commercial sector.

ASSOCIATE MEMBER GEESMAN: Why is your industrial elasticity so low compared to say chemical?

MR. FORE: We think the reason here is the lag involved here. Industrial changing, when you have a change they are going to respond much slower because they're going to have a lot of stuff backlogged on order that can go ahead and be filled before it really comes through the system. So the industrial sector, we think, responds a little less to the price simply because of that. there is a longer lag time there.

ASSOCIATE MEMBER GEESMAN: What industries are we talking about?

MR. FORE: Well, we have, we have just taken an aggregate of them.

ASSOCIATE MEMBER GEESMAN: In California or is that a national number?

MR. FORE: This is a national.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. FORE: This is not really based

specifically in each individual state.

All right. In the power gen side in the East using the Altos work where basically this is the parameters they have in there that they are considering in order to get their gas burn. When we look at the California side the electricity department has provided us with one. They're basically using average conditions for the forecasts we have in there now.

It has been updated from the last IEPR report but it is not the final gas demand that we'll put in there. When they get a final one done we'll put it in and rerun the model to get a new demand forecast.

ASSOCIATE MEMBER GEESMAN: You know, I think there might be some value if just as a sensitivity we also ran the same model that you used on the East to indicate what electric generator demand would be in the West.

MR. FORE: I think that probably would be appropriate.

ASSOCIATE MEMBER GEESMAN: I know there's a tendency to want to support the home team and all but I think if there is a serious difference in results the Commission ought to know about that.

MR. FORE: Well I did a comparison of the EIA regional demands looking at the census regions specific, Mountain and stuff. We basically overlay the EIA in the West, there is not a great deal of difference. When we go to the East the gas burn we're showing is much higher in the South Atlantic and in the East North Central and the West North Central, which are heavy coal users. So that's where we have our big difference in terms of the amount of gas being used in power generation.

Okay, we take a look at the overall gas demand for the North American continent. That includes Canada, the Lower 48 and Mexico. In Mexico basically we use the NPC data, that goes in there. Canada and the US is using the factors we showed before.

We note that there's a trend difference at around 2012. This is basically related to the price. We have gas prices in our forecast, which will be covered later, declining in the early years and so we see a more rapid growth in gas demand. As the price starts to increase we see it leveling off and not growing quite as fast so you see a varied distinction in the trend in our demand forecast.

The overall growth is not very high. we're looking at two percent for North America. The US accounts for about 83 percent of North American demand so it really is the one that sets the growth for the North American market.

When we look at the demand for Core, which is Commercial and Residential, the driver here is basically population. And we see an increase both in Canada of about one percent, the US 1.1. Mexico is higher and part of that is because they really have no infrastructure for gas right now. And we see that expanding somewhat and that's why we see a rapid growth. But it was so low to start with it doesn't even show on the chart so any increase makes a rather big jump on the thing.

When we look at industrial demand we have two factors working here. We see a growth early years and then it starts to taper off. Within the Industrial sector we have two things happening in the early years. We both have declining gas prices, which we would think would increase the industrial consumption. We also have declining oil prices during that time from the forecast so they're kind of offsetting each other so we don't see a really rapid increase there.

In the later years as the gas price goes up the oil price in the EIA forecast doesn't really start taking off until after the forecast period and so that's why I think we see some damping of the demand out there. Also we see a falloff with the enhanced oil recovery in California because of lower oil production. The main growth is the Canadian Tar Sands and Mexico has some increase in the gas. But overall in the US we see basically flat demand. I mean, we call it a minus two percent but that's outside of the model's ability to predict.

This is a real growth area is the power generation in the US. in the West we show it as basically flat, it grows a little bit in Canada and in Mexico. But it is in the eastern part of the US is where we have the major demand increases. As I indicated it is basically in the East North Central and West Central and South Atlantic. New England doesn't really increase that much. Surprisingly Texas and the West South Central doesn't increase all that much. But they are all higher but not as great as they were in those other three sectors.

If we look in the western US and Canada they're fairly flat. They grow a little slower than the rest of the US and basically that's because of the power gen. We don't have as much increase in gas burn in the West as we saw in the East and that's why we have a slower growth rate here in the West.

If we look at the Wester US we can see when we break out California, Canada and the Western States without California, we can see that they all are increasing a little bit but there is no dramatic growth really that I can see in there. The Western States, it's a little higher out at the end. That is basically driven more by population. We have a big increase in population in the Arizona, Nevada -- California has a decent increase in population but it is still under two percent, where some of the Western states are growing at greater than two percent and that's where most of that growth is coming from.

I put in our population just so you can see an idea of what we really see. Arizona is a big growth area. California is not bad compared to some of the other states but Arizona and Nevada are the bigger ones. The rest of them are really fairly decent. Wyoming is a low one and Montana. You don't see a lot of growth when we look at those individually.

And British Columbia, again, their growth in population is fairly modest and that's why we don't see a lot of growth in Western Canada.

When we look at the residential demand you can see the impact the population had. It's greatest impact is in both the California market and in the Western States. California is so big to start with, when you get about a one-and-a-half percent increase in growth it does translate to higher gas demand. Canada you notice stayed fairly flat during that time period.

In the commercial area, again we don't see a lot of growth. Canada is a little bit faster than the rest of them. The Western States and California are just about the same rate of growth. We found another thing that would indicate that we would expect a greater rate of growth or a decline because we did have about a three percent gross domestic product during that time period. And the population may be the two factors to show that growth.

When we look at industrial demand we're seeing California declining slightly or basically staying flat. Western Canada's increase is basically on the Oil Sands. we see an increased production in there. We see more gas being consumed for that. In the West again it's basically flat. The Oil Sands is somewhat of an iffy statement in terms of how much it grows. There are talks about reducing the gas demand by using other technologies to extract the bitumen from the oil sands but it is something that we wouldn't see taking place in the next ten years.

Okay. When we look at power gen, this comes from the electricity office. We see Canada staying fairly flat in their forecast. The Western States, you see it going up and down and that basically I think has more to do with how they see the stuff being transmitted and new additions later on. But we see nothing that is really surprising in that area.

If we look at California we see it fairly flat. Demand power gen is the big area followed by the residential. But we see a fairly flat demand all the way through for the state.

When we look at the regional ones, again the residential is basically population. The difference in growth you see between the different utilities, which basically are based on the growth in population we saw in their districts. And the ones that had the greater population growth are the ones that show the higher growth in our demand.

The same with commercial. Population was one of the factors in there. We're using the same domestic product and other factors, heating degree days and stuff, so that's not having an impact on the variation between the districts.

Industrial demand. The orange is the enhanced oil recovery gas. that's where we see the big decline over time with declining oil production that we expect in the heavy oils that are being produced in the state.

Looking at power gen. This basically is just a reflection of the gas generating capacity in the districts and what might come on in the way of new generating capacity. So that's what causing basically the changes that are occurring in the power gen sector.

Overall our conclusions: We see the US or North America growing about two percent. We see the West growing less. When we look at gas demand domestically the US is going to continue to dominate all the way through the forecast.

The fastest growth area is the electric power and 5.5 is the national average, it's around 6.5 in the East and lower in the West. In California we say basically flat growth, .8.

Basically we're seeing increased use of renewables, which is reducing potential gas burn in the electric generation. Slower growth in new capacity being put on. The reduced gas demand for enhanced oil recovery. Basically flat growth in the industrial sector is one reason why we see such a flat level of growth in California.

Okay, any questions?

ASSOCIATE MEMBER GEESMAN: How did you determine your assumptions on gas demand for enhanced oil recovery? Was that driven more by the geology of California oil fields or --

MR. FORE: Well it's really more by just looking at the trend we're seeing in production falling off right now. We're seeing increased drilling but we're not really seeing an increase in the oil production in the state. I don't --

You know, the field is very mature down there and so we don't expect any new fields to be found that would be of significant size. So that's basically what it is based on is just the declining trend in the oil production.

ASSOCIATE MEMBER GEESMAN: You didn't try to replicate the economics of --

MR. FORE: No.

ASSOCIATE MEMBER GEESMAN: -- oil prices or gas costs for EOR?

MR. FORE: No, we didn't do a ratio of that.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. FORE: We just basically looked at the steam required and did a base off that.

ASSOCIATE MEMBER GEESMAN: Okay, thanks.

PRESIDING MEMBER PFANNENSTIEL: Yes, Susan.

ADVISOR BROWN: Excuse me, Jim, I had a question for you. In calculating the California-specific natural gas demand how did you account for the effect of state-approved efficiency programs?

MR. FORE: Well of course it comes from

the demand office and they have accounted for that. On the electricity side, the electricity office has accounted for the renewables of 20 percent up to 2013. They put that in so that's one reason why we see a reduction in gas in the electricity side.

In the actual demand numbers from residential, commercial and stuff, that really is coming from the demand office but we have felt that the changes basically were due to population on that. I am not sure how they have accounted for the efficiency in their equipment in new appliances and stuff but basically they put that into their forecast when they do it.

ADVISOR BROWN: So someone else on the staff would have to answer that question.

MR. FORE: The demand office is the one that gives us those numbers for California that we put in.

ADVISOR JONES: Susan, I think from reading the report it indicated that efficiency programs that are committed through 2008 are included --

ADVISOR BROWN: But not beyond.

ADVISOR JONES: -- but I am not sure

after that.

ADVISOR BROWN: Okay, thank you very much.

MR. FORE: That's true on the electricity side I know for sure. On the demand forecast since it's what, it's an '05. I'm sure that anything that has come up since then is not in the forecast at this time.

COMMISSIONER BOYD: Jim, an observation more than a question or a comment. It's been interesting to read of late about the Alberta oil sands and the interaction. With the new interest in the low carbon fuel standard that is spreading around very rapidly in the states and now the provinces and the potential impact on the production of those oil sands, and thus there would be a ripple effect on the use of gas.

I know it's nothing you can forecast now but I found it interesting to read in the last week or more that since the carbon footprint of Alberta Tar Sands oil is presumed to be extremely high there is suddenly question being brought about whether they will be as popular as we thought they were up until perhaps this year. So it will be interesting to follow that. I know you can't predict or project anything but just another ripple on the pond.

MR. FORE: But I looked at it the other day in the press, you know, and they're talking about running a line all the way to the Gulf Coast to take Oil Sands crude all the way down there. And they were talking about running a line over to the BC to ship it off to Japan. So, you know, it's sort of a flip of the coin as to which way you want to go.

But we didn't take into account, you know, they're talking about how they might reduce their gas demand with new technology. And we did not account for that because of the shortness of the forecast period.

PRESIDING MEMBER PFANNENSTIEL: Other questions from the dais? From the public?

MR. MYERS: Richard Myers with the California Public Utilities Commission. What accounts for the, it looks like a large increase in the California power generation demand for PG&E between 2009 and 2010?

MR. FORE: We'll turn and look at the electricity office and let them come up and address that because we have taken it straight from their work.

MS. TANGHETTI: A lot of times you see the lumpiness -- Angela Tanghetti with the electricity analysis office. Many times you see lumpiness in the forecast as a way new generation comes on line and possibly other things as possibly nuclear power, nuclear refueling schedules and how those are put in the model. So you do see some kind of lumpiness in the forecast from year to year by region in California. Does that?

MR. MYERS: It does appear that there's about a 25 percent increase from one year to the next. Are you sure it's just the lumpiness?

MS. TANGHETTI: Of resources being added?

MR. MYERS: Whatever accounts for that demand, I'm not sure. Is it just resources or is it the lumpiness in the model?

MS. TANGHETTI: Exactly, I can't tell you exactly there but when we do see lumpiness it is basically new generation coming on line when we see increases in natural gas demand like that.

SPEAKER IN AUDIENCE: PG&E has about 2,000 megawatts coming on.

PRESIDING MEMBER PFANNENSTIEL: Excuse me, you better, you better go to the podium if you want to add to something.

MS. TANGHETTI: There is, again, quite a bit of new generation coming on in the next few years regionally within California.

DR. ARTHUR: I had a question as to how the projected growth rates compared to say the last five or ten years. Just so I get a sense of whether we're growing faster, about the same or slower in these categories. Can you just comment on that briefly.

MR. FORE: Basically on the electric side we're going slower because we've had the big increase in generating capacity. On the residential/commercial, the industrial is definitely down because we have lost some of the gas being burned there. The residential and commercial, I'd say it's down slightly but not significantly. Basically it would be due to appliance standards and building standards changing over time has reduced it.

I mean, if we look at the per capita consumption in California, it's went down greatly over the last say 20 years. And basically that is the efficiency standards coming in and taking effect. How much they are going to play in the future? I mean, you know, how much can you insulate a home before you start not getting anything, you know, out of it, and the same with the building standards. But it has been coming down. I think it may be starting to flatten off somewhat but it's too early really to tell.

PRESIDING MEMBER PFANNENSTIEL: Other questions? Go ahead.

MR. COWDEN: Bob Cowden, PG&E. I guess I wanted to maybe respond a little bit. When we look at our gas demand forecast that we generate we see a higher growth rate than what is in the CEC assessment. In our forecast we don't quite see the stair step between 2009 and 2010, it's more of a steady growth 2008, 2009 through 2010.

And it is hard in these gas models to kind of dissect the one thing that may be causing that. You know, in our models relative prices in different regions of the WECC have a big effect on relative gas demand. So, you know, there could be something going on. I guess I'm curious why it looks like the SoCal gas demand is going down at the same time the PG&E demand goes down in their forecast. I'm kind of wondering what is going on regionally between some of the dispatch of generation.

MS. TANGHETTI: Yes, you're correct, regional price differences in various years do affect those -- the lumpiness of the forecast as well. So yes, you see one area going up, one area going down, and it is sensitive to price.

Overall gas demand probably is going to stay the same but you are going to see shifts regionally in where the generation is coming from.

MR. TAVARES: By the way, we got last night some comments from SoCal Gas in San Diego. So if we have time to address those we will do it after the next presentation. This is in regards to our forecast and their forecast so hold on to that. Any more questions on demand? Go ahead.

MS. SCOTCHI: Jill Scotchi, PG&E. Like Bob said, we're not seeing the -- we're seeing a greater growth rate in electric power gas demand than 1.1 percent so I would support Commissioner Geesman's suggestion that maybe we run an integrated gas power model to get similar gas demand forecasts in the West so we have an apples to apples comparison.

COMMISSIONER BYRON: I believe looking at the report the PG&E annual change that we're projecting, correct me if I'm wrong, looks to be about two-and-a-half percent per annum. On page 22 of the report.

MR. FORE: Yes, that's close to being right.

COMMISSIONER BYRON: Not one percent.

MR. FORE: And we will, when we get a new forecast we will be updating that so you will see some changes in what we presented in terms of the California gas demand and the power gen in the WECC when we put in the new forecast.

DR. ARTHUR: Just as a point of clarification. This is Dave Arthur, City of Redding again.

If I understand the assumptions behind those numbers it assumes, for example in the case of renewables, that there is sufficient transmission in order to deliver the renewable energy to the load.

And second, I presume that you do not have any large scale cutback of coal-fired generation as a result of cap and trade or other kinds of things that would have to be supplemented or replaced by natural gas fired generation; is that correct?

MR. FORE: They do have, the transmission is there to move the renewables that are in there to the load centers.

DR. ARTHUR: That will make some people very happy.

MR. FORE: I didn't see a big cutback in coal but it does allocate it depending on price.

MS. TANGHETTI: Coal generation, the existing coal generation basically stays as it is. The forecast of new coal coming on line for instance, it's probably two-thirds less than the forecast that we had in the previous IEPR as far as generic coal coming online throughout the WECC. So that does have an impact in our results.

MR. TAVARES: Okay, we're going to change topics and we're going to go to the gas price forecast. Bill Wood will make a presentation, And then, again, if we have time before lunch then we will address, we'll allow SoCal Gas to make some comments. Bill.

MR. WOOD: Thank you very much and good morning to all of you including the Commissioners, it is good to be here with you.

Normally the gas price presentation is given after demand and supply and infrastructure. But if you notice this little word right here, retired, that means that I have got commitments this afternoon which are taking me away so therefore my presentation is going to be out of order.

And normally my presentation, I would tie together everything that has already been said. So now it's going to be a little bit difficult to try together things that haven't been said yet. So bear with me as we go through this.

I am going to start with conclusions and then build on how those conclusions came about. First off we see that the natural gas prices at Henry Hub and prices run, decline as we see happening in the NYMEX and then rising again to around $7. Catie Elder later on this afternoon will be showing the differences between our forecast and Henry Hub and also other forecasts.

Our analysis also indicates that there are more supply options available which increases gas-on-gas competition in the US.

We also have noted that the gas spreads between Henry Hub and several other hubs are increasing. That then indicates that Henry Hub is escalating at a slower rate than say the locations here that are serving California like Malin or Topock.

And a number of the basis spreads that used to be negative, because of the growing differential between those hubs and Henry Hub, are becoming positive. Some remain negative but there are a number of them, including California, that do become positive.

And of course my final conclusion here that comes out of the analysis is that California used to enjoy a discount for natural gas at the border and in the future it looks in about three to four years we may actually be having to pay a premium for our natural gas at the border.

Now most of my talk is going to be centered around this graph. It looks a little bit busy, it has a lot of information on it. And really looking back I wish I had made overlays for this so that you could see what I'm talking about. But first, all of you that have your papers with you you're going to build your own overlay as we go through this.

So get out your pencil and in the 2006 a line from the New Jersey-Southeast Penn, which supposed to represent Transco 6 gas flowing into New York, and bring it all the way down to the AECO price, right in $1.70. Now let's go to the other end of the forecast and do the same thing again and write in $1.00.

That represents the price differential between the selected hubs that are showing here. Basically that is telling us that there are more supply options available to customers which is reducing the regional differentials, reducing volatility, to the point that over the next 10 to 15 years those differentials will collapse by about 70 cents in 2006 dollars. That's number one. Let's see, I've got to look at my notes here. Hang on a second, which one I want to do next. All right.

Next thing I would overlay, I would overlay this very dark blue line. That represents the Henry Hub price. That is how -- No, I want to use this. I can work with this very nicely and everybody can see what I'm talking about and I can move it handily. All right, this represents then the Henry Hub price.

Early on notice where Henry Hub is in

comparison to California prices here. It's high. It's higher. And the only one that is higher than Henry Hub is the New York price. When we get to the end of our forecasted period we see that Malin, New York and let's see, this is Topock, are all higher than Henry Hub. Only the gas coming from the Rockies is below or approximately equal to Henry Hub.

What this is telling us then, this is implying that the pipelines that are delivering gas from the Southwest and from Canada are flowing at lower capacity. And that will be, Leon will be showing you that this afternoon. Yes, that is the case. With regards to the Rocky Mountain pipelines, Kern River will be flowing at or near capacity for the forecasted period.

Now this is because of the impacts of LNG coming into California and the rest of the US. Now if LNG was not available these pipes here, meaning the pipes coming from Canada and also coming from the Southwest, would be flowing heavier. That would then indicate then that prices in California would be higher without the LNG than it is with the LNG.

Okay. Now the next thing I want you to

do is in this area right here draw a line. A horizontal line and write 12 percent. And then in this general area draw another horizontal line and write 40 percent. And in this outer area draw another line and write 50 percent.

Now what those represent then is the share of LNG flowing into the Gulf Coast during our forecasted period. Initially LNG is flowing at 12 percent. That's sustaining, it's not enough to bring down the Henry Hub price.

We see that it increases to around 40 percent in this general area and you can see that Henry Hub has dropped considerably below most of the sources.

And by the time we get out here we're approaching over 50 percent of the supply coming out of the Gulf Coast is LNG. We see that all other sources, at least that I have indicated here, are higher than the Henry Hub.

There was another point I wanted to make on this. Okay, I don't remember what it was, we'll just have to go on.

ADVISOR JONES: Bill, I've got a question.

MR. WOOD: Yeah.

ADVISOR JONES: What accounts for the up and downs in between years?

MR. WOOD: You know, it used to be that everybody complained because our forecasts were real smooth. (Laughter) And they said, well that doesn't really represent what's happening in the market. Now we put, we show what the market is really doing based upon new supplies coming in and shifting in demand and that sort of thing and so we get the sawtooth look.

Maybe what we should have done is normalized all of these so we get one nice, smooth curve here to representing all of them. But basically, Melissa, it's based upon how different supplies come into the market and how they interplay at the point of time when they come in.

All right. That was the other thing I wanted to indicate. No, we'll do that on the next slide. All right, this is just kind of a summary of what I told you so I'm not going to go over this anymore. Let's go -- What happened to my other? That other slide didn't get in here. Okay, well let's go back. I'm going to go back to this one then.

In this slide one of the interesting

things is when I'm talking about the Gulf Coast. The Gulf Coast continues to produce in the area of about 20 to 25 billion cubic feet a day. But the LNG add-on is about 3 billion cubic feet a day per year. So it ends up that by the end of the 20 year period we're looking at three times ten, it would be 30 billion cubic feet of gas coming through here. And overall supply coming out of the Gulf Coast is in excess of 50 billion cubic feet a day with about half of it being production and half of it being LNG.

I had a graph that I thought was going to get in but apparently it didn't get -- I made a modification this morning. I was going to show the differential between the prices. The actual price directory between LNG landed in the Gulf Coast, production in the Gulf Coast and Henry Hub. What happens is that Henry Hub and Gulf Coast -- Henry Hub and LNG prices are almost right on top of each other. So basically then it looks like the LNG prices are driving the Henry Hub price. The production price is 10 or 15 cents below both of those too.

Now this particular slide is a little bit busy but I only need you to have a look at one piece of it, that's the historical and then the 2006 piece. Now what I've done here is I have gone to Natural Gas Week who publishes annual average hub prices and determined what the differential were between these selected hubs and the Henry Hub and compared the historical prices versus the 2006 is what I want to look at.

If you look at SoCal, right on. If we look at Malin, right on. If we look at AECO there's a little bit of difference here. But if you look at 2007 and compare that to what was happening earlier on in the decade you'll see that it's fairly close to being the same. Now if we look at Kern/Opal they are not the same. There is some correlation here but at least they're both in the same relative ballpark and the same sign.

If we look here at New York we're, I would say we could check this one off as being correct. We have this outlier that occurs in 2005 but all the rest of the years are fairly close and you can see that it's declining and we continue to decline. Chicago is probably, you could consider that a check also because if you look back in here we're talking about plus or minus ten percent. Here we're talking about minus ten percent then growing from there to positive.

So basically what the model is telling us then, we may not agree with the actual price forecast because it may be too high or too low depending upon others' perspective. But what it is telling us is that it is giving us the right perspective between the different regions throughout the US so that we see how the market is really operating. We may not have the right forecast but we have a forecast that is regionally telling us how the market is going to operate.

Let's see, what else. I had one other thing. One of the things I was thinking, rather than always just comparing a point forecast that we have with other forecasts it might be interesting if it is available to actually look and see what kind of differentials they have going within their different hub locations within those models. All right, this is a summary of what I just said.

All right. This is the only end use price forecast that I am putting in my presentation today. Mainly because the forecast that we're using is primarily used in the electricity analysis that the Commission does.

Again, these two lower lines represent deliveries off of Kern River and off of El Paso Transwestern directly to power generation.

You can see and you would presume that they are lower than what would be delivered to a gas utility, which is shown in the upper lines. And that of course is that those power plants don't have to pay for the distribution costs.

Now early on it's kind of interesting. We see early on that the PG&E price is lower than for SoCal and for San Diego. I have in here also Otay Mesa. I don't know when Otay Mesa comes on but we at least have a price forecast for them that's fairly close to what San Diego is.

But during this period of time is when Costa Azul comes in. During the 2009-2010 time frame we have Costa Azul coming in. SoCal Gas San Diego prices differential between PG&E become much closer.

And then when we look out here to around 2012, 2013, in this general area look what's happening here to Otay Mesa and to San Diego prices. We actually see a disconnect for San Diego from what is occurring in San Diego -- what's occurring in the SoCal system and PG&E.

Basically what's happening here is that our model is kicking in the second phase of Costa Azul. So we're going from a Bcf a day to two-and-a-half Bcf a day. One Bcf a day is actually being delivered into San Diego and then through to SoCal Gas. What is happening then is the gas is being priced as if it was being in SoCal Gas so therefore San Diego being in the middle pays a little bit less.

Now there is a problem with this and we're going to have to correct in our forecast our believe, we'll have to look first to see, but currently there's only three to four hundred million cubic feet a day of capacity to flow from Mexico into San Diego and there is no capacity to flow from San Diego to SoCal Gas.

We'll have to look to see what kind of costs are put in there. But if those are low costs then this is going, this shape is going to have to change because we're going to have to change the model to either restrict the quantity of gas that can come into San Diego or jack up that price that is moving gas to SoCal Gas through San Diego.

After that occurs then you can see that

San Diego tends to act a little bit more like an interstate pipeline than it does as a utility in terms of what price that's available.

Now one other point I want to make out of this. I've only showed six, six price forecasts, EG price forecasts, that we do within our office that are supplied to the electricity office. Actually we do a total of 34 of these representing a lot of different areas and deliveries off of different pipelines. So each of those areas then will have an individual price that is representative of that area.

That then, given the basis of what is going on here, it makes some of those areas more competitive than other areas. So if you're building an EG plant of course you want to be along an interstate pipeline because it is going to be the cheapest but you don't know what the transmission line capability is going to be.

Angela in her work in the electricity office takes care of that. We provide her a price forecast, she gives us a -- based upon that she will run her model and gives us a demand forecast. We put that back into our model and we iterate until we're happy with what the end results are.

Okay, here is a summation of what I hopefully have said.

And that's it. Any questions?

PRESIDING MEMBER PFANNENSTIEL: Questions from the dais?

Questions from the public?

MR. BILLINGS: Kevin Billings with Kern River Gas.

Bill, on your forecast here you show, this last slide that shows forecasted electric generation natural gas prices. You show Otay Mesa gas pricing there.

MR. WOOD: Um-hmm.

MR. BILLINGS: Where did you get those numbers and what was the basis or the assumption for that?

MR. WOOD: Okay, within --

MR. BILLINGS: Because I'm assuming, I'm assuming an Otay Mesa pricing then reflects LNG pricing.

MR. WOOD: That is correct.

MR. BILLINGS: Okay, where did that come from?

MR. WOOD: What happens at this point is that Angela tells us when Otay Mesa comes on. I don't remember exactly when it is or if it does come on. But there is, we do have a price that is associated with any demand that may be put there. And that comes out of, that comes out of our model. That comes out of the NARG model. But that price is, it basically represents a tailgate price coming out of Costa Azul plus the transportation component on TGN to get it to Otay Mesa. The same way as going to San Diego.

MR. BILLINGS: Maybe Dale would answer this, I don't know. It just seems to me when LNG is trading over in Asia for $10, $12 a BTU, I don't know why it would land over here for $6.

MR. WOOD: Well, I just work with the numbers. (Laughter) Somebody else is going to have to talk about the assumptions behind them.

DR. NESBITT: Well first of all LNG will trade for $12 a BTU when you're short of capacity. The assumption that's submitted is you're not short of capacity.

And what LNG does, including in Japan, is it takes the fair market value of gas in Japan, which the Japanese conveniently set to oil price so they can attract the cargoes because they don't have any storage. They have to bid it because they need that gas real-time at time of peak. But when they don't need it, it falls to the next available source. And the next available source under this set of assumptions is this index price and that's what they get for it, netted back exactly as Jim said.

So it would be nice if you could sell it for $12 everywhere, you can't. One other issue about Asia that was never mentioned. Japan is minuscule. Japan isn't even three Tcf total market. It's about two. It's about six Bcf a day. LNG is going to overtake that just in Gorgon in the Northwest Shelf of Australia fairly quickly under most peoples' assessments.

MR. WOOD: Thank you, Dale.

There was another hand.

DR. ARTHUR: Dave Arthur, City of Redding. Could you elaborate a bit more on the precipitous decline between 2006 and 2008.

MR. WOOD: Which figure are you on?

DR. ARTHUR: You can pick any one of those you want. It goes straight downhill on all of your price charts from 2006 to '08. And needless to say, the forward curve is not quite replicating that particular pictorial.

MR. WOOD: Well if we had Catie's presentation here we could compare what's happening with our forecast with the prospective three year forecast is on the strip for NYMEX. Basically NYMEX will follow the same sort of pattern. But if I remember right it's about up here and comes down something like for the three years. So we are --

We tried to make the model replicate what is happening within the industry now. So therefore we've tried to replicate what's happening with regards to NYMEX. Now these numbers are directly out of the NARG model. They have not been doctored to represent what is coming out of -- doctored to represent NYMEX prices. So again, the NYMEX figure, NYMEX really is coming done something like this. So it's not quite as low as our forecast is when you correct it and then put it into 2006 dollars.

MR. FORE: Let me address some of that for you. One reason the price is falling, this is Jim Fore with the CEC, is the LNG that we have coming in. We put in a capacity and we estimated when the new capacity would come on up through 2012 and then we let the model bring it in as it would.

We don't put any restrictions on this on the first pass and so it probably may be overstating what would actually come in. But because it is bringing in so much that is what is driving the price down.

If we go in and put some restrictions on it we would see a different trend there. But on the first pass we didn't want to try and outguess the market so we said let's see how much LNG will come in if we just let it flow under economic conditions and go to the best market and get the best price. This is what we get.

Now we'll take a look at the volume of LNG that's coming in. If we think it's either too high or unsustainable based on what Jim Jensen has told you this morning we'll put some restrictions in the model and we'll see that price come back up a little bit. But right now it's just an unrestricted flow of LNG that's driving that down.

MR. COX: Rory Cox from Pacific Environment. Regarding the price moderating influence that you see of LNG and the Henry Hub. Wouldn't there be a completely different dynamic going on on the West Coast? And I'm thinking in particular there's EIA estimates that show that the dollar amount to bring LNG ashore on the Pacific Coast is much higher than it is on the Henry Hub and it is a completely different dynamic. As Mr. Jensen covered this morning, the trading regime is different in the Pacific than it is in the Atlantic. So is that, can we be so sure that it is going to have such a predictable impact on prices?

MR. WOOD: Well I think Dale kind of covered that particular question earlier with regards to the size of the market here versus the size of the market elsewhere and whether there are constraints within that marketplace.

Basically what we're seeing, I think if I remember correctly, we're seeing about 2 Bcf a day, 2.5 Bcf a day being landed at Costa Azul in the outer years. Of which about 1,500 of that is -- let's see, there's 1,000 coming across to California at San Diego and there's about 300 to 500 being consumed inside of Mexico. Which leaves another Bcf that's making it all the way up flowing backhull on the northern border pipeline to -- the Baja pipeline, I'm sorry.

Backhull on the North Baja pipeline to

Blythe where it can go anywhere and come into California either through Southern California's southern line. It can go up El Paso's 1903 up to Daggett. It can flow east into Arizona for consumption there. Or it can even by displacement end up heading east of the Mississippi. We just, the model has the molecules coming to Blythe and it's kind of difficult to say exactly where it's going after that. Dale.

DR. NESBITT: Dale Nesbitt. One elucidating comment on your previous chart where you talked Malin and Topock Basins going positive relative to Henry Hub. That's why in part you have a higher landed cost and therefore a higher price of LNG on the West Coast and that is going to materialize in your runs here in terms of the movement towards premium basis at Baja, Topock, Malin, Pacific Northwest, et cetera. So it was on your previous chart, I just wanted to point that out.

DR. ARTHUR: I would just like to make one market comment for the Commission as it relates to the LNG issue. We have been in the market buying from one of the primary participants in Costa Azul over the last three years.

When Russia pulled the spigot the first time interrupting the flows to Europe the mutli-year impact on the price of their product was $1 and that occurred in two weeks. As you take Commissioner Geesman's view that it is better to err on the side that does the least damage I would keep Russian politics in mind.

MR. BILLINGS: Kevin Billings, Kern River. I would agree with your statement there.

My question then is, Mr. Jensen this morning came in and gave a rather skeptical view of the certainty of LNG supplies. And now we come in here and this model would seem to indicate that it's very robust. That you're going to have one to two Bcf of LNG available to California.

Does the model take into consideration some of these uncertainties and assess some value to these uncertainties? Because we have very diverging points and opinions here.

MR. FORE: Well let me address that again. At this point it doesn't. The movement of LNG in the world is based on the world trade model and it's based on economics. We have not put any restrictions in in terms of how many liquefaction plants might be built further out or regasification.

Now if we look at the permitted plants for regasification in the US, we looked at that and we said, okay, we know what's under construction that we felt would come on. And then we let the model flow and determine the amount of LNG that would come in.

The total amount that comes in is extremely high but actually if you add it up the plants that have been permitted, not necessarily under construction, if they all were built that forecast would be true if they could be filled up. So, you know, we're optimistic. We think we're probably over optimistic.

But we'll have to go back and look at how we might restrict it. We might put in something in terms of the capacity, might drop out some of the regasification facilities. But on the first pass we didn't want to do that. We didn't want to second guess what we thought the world would be like. We wanted to see what it would be like based on the model outcome and then decide whether we believed that's the way the world would be.

And that's one of the reasons we do

scenarios is to change this outlook of the world and then come up with a new deal. So we are rather optimistic and it does drive the price down, as you see here in the West where we talk about the LNG coming in.

We also have another factor that influences the West and that is the Rockies Express Pipeline that is in there. That is taking gas out of the Rockies, moving it into the midcontinent all the way to New York, which will affect the amount of gas available to California and it will affect the price. So that's an impact that's in there that we haven't talked about yet.

We're also looking at Canada, you know, and we talked about the oil sands. A lot of the Canadian gas, if Canada changes their outlook on coal-fired generation in the East and converts to gas-fired, there will be a lot of gas moving in Canada to the East and not coming to the West.

So those are some of the things that we kind of have in there that we were taking a look at now to see if we're going to change it or not change it. That's why we want your comments. So we know if we need to be cautious in some areas if you have actual data that shows us we're wrong.

That's what we're looking for right now.

MR. TAVARES: Yes. And keep in mind that this are, again, the preliminary results of the run so we are accepting other comments. One last question here.

MR. MYERS: Richard Myers of the CPUC.

Bill, with regard to one of you bullets where you say:

"SDG&E's service area is flooded with LNG competing for the SoCal Gas market. Being in between the two SDG&E receives a lower price than SoCal Gas."

I was wondering how you came to the conclusion that SDG&E would get a lower price than SoCal Gas. Are you assuming that there is a transportation cost?

MR. WOOD: Well yes, there would be a transportation cost associated with moving the gas from one area to the other.

MR. MYERS: Well, the CPUC has recently adopted system integration for the Southern California area and basically there would be a single transmission price for the Southern

California area.

MR. WOOD: Well it may very well be the way the model -- I have to look to see what the structure is. I've been away from this too long. But it may very well be that the EG demand centers that we have in San Diego have the option of either pulling from SoCal Gas through Rainbow Station or pulling gas from TGN.

SPEAKER IN THE AUDIENCE: TGN, it is that way.

MR. WOOD: And it is that way?

SPEAKER IN THE AUDIENCE: It is that way, yes.

MR. WOOD: So you have gas flowing into San Diego where the power plants have the option of either buying gas from SoCal Gas or through SoCal Gas, meaning Southwest Gas, or buying gas from LNG through TGN. They have both those options. So they're getting a supply mix.

And because it is being flooded with LNG they are not, they're getting the LNG price and not the Southwest price that SoCal Gas is seeing. They may have the same markups with regards to transportation components inside both utilities but the commodity price is going to be different.

MR. TAVARES: Okay, we are done. One more question there.

MR. PAK: Could I just ask a quick question?

MR. TAVARES: Go ahead.

MR. PAK: Al Pak for Sempra LNG. Mr. Fore just said something that was inconsistent with the report. And I think this is at page 41 where it indicates that the preliminary runs of the model showing the effects of the operation of Rocky Mountain Express Pipeline indicated that whatever the effects of the pipeline were on the Cheyenne Hub prices there would be no effect on the prices at Opal, which serves California. I think Mr. Fore indicated just moments ago that that was not true and I just wanted to know which position the staff really was taking there.

MR. WOOD: If we look at Opal. When Rocky Mountain Express comes in right here in '09. So it's coming in at '09. This is the differential between Opal and Henry Hub. There is a drop that occurs in 2010 and there is a -- but it looks like it may be just a continuation of -- I don't see anything that's really dramatic that's showing here. Of course it's up to your interpretation of what's dramatic here within these price spreads. Jim.

MR. FORE: Well, we do have the Rockies in there and it is taking gas out. The full impact, the Rockies are going to be competing with the LNG that's flooding into the Gulf Coast right now so the price is kind of being set more by the Henry Hub price and the LNG impacts on that.

But there is volume that is taken out of the Rocky Mountains area that will go east that originally would be in place and could come here and so there is some impact. The model, it has Henry Hub and Opal tied together. I mean, Cheyenne and Opal are tied.

MR. BRATHWAITE (FROM THE AUDIENCE): Yes.

MR. FORE: And so it is showing some impact there.

MR. BRATHWAITE (FROM THE AUDIENCE): Yes.

MR. FORE: But not a great deal I guess at this time.

MR. BRATHWAITE (FROM THE AUDIENCE): But if you look at the

COMMISSIONER BOYD: Leon, you've got to

get up.

MR. WOOD: You've got to come and -- Come on, Leon.

MR. BRATHWAITE: I am Leon Brathwaite with the California Energy Commission. I am the guy who do all the modeling. Anyway, if you look at this graph which was constructed by Bill you will see that the basis really is not when it starts from 2006 going all the way down to 2017. Now the Rockies Express do come in around 2009. As a matter of fact it fills out and goes east.

So you see, you are seeing some effect, even though you could probably say it's a continuation of the trend. But you are seeing some effect of that pipeline coming in.

Now I guess there might some little inconsistency in terms of what the report said but maybe that's something we need to look at and make sure we correct it in the final. Catie, you wanted to say something.

MS. ELDER: I was just going to add one point which is, remember Dale pointed out and I am going to amplify later in the afternoon for those of you who are awake that long (laughter) that we have got full access to all of the resources, all of the reserves in the Rockies, at least at this point, assumed in the model.

That's something we've put on the list of things that need to have a look taken at to see if that's really the best assumption that we can make. There's certainly some restrictions on drilling that come out of EPACT, for example. There is a ban on Montana front range drilling. There is talk of a new ban on Wyoming Rockies front range drilling. There are other areas. Powder River Basin has been impacted by some issues with drilling and dealing with the water that comes out of the coal-bed methane production.

So we think that one of the things that's one our list to sort of tickle the staff about is to say, you need to take a look at that Rockies total access assumption to see if that really makes sense.

Now the question will be, if we restrict that we can get access to in the Rockies in the model will we then still see virtually no difference between the Cheyenne Hub price and the Opal price? That's what we don't know until we do that run.

PRESIDING MEMBER PFANNENSTIEL: I think

that we are about to close the morning session.

Ruben, do you have anything further for this morning?

MR. TAVARES: No, I just wanted to mention that we received the Southern California Gas comments before midnight last night and they wanted to make some comments. But we can start the afternoon with their comments if you prefer.

PRESIDING MEMBER PFANNENSTIEL: I think that's a good idea.

MR. TAVARES: Okay.

PRESIDING MEMBER PFANNENSTIEL: We'll break now until 1:30 and then reconvene.

(Whereupon, the lunch recess was taken. Commissioners Pfannenstiel, Boyd and Byron did not return after the recess.)

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AFTERNOON SESSION

MR. TAVARES: To my knowledge we lost some of the Commissioners. Don't take it personally. It is not the topic, it is not the speakers this morning either, it's just that they had other commitments. But we've gained another advisor, Tim Tutt is here with us.

We're going to depart a little bit from the agenda. We have three more presentations officially. However, I mentioned before lunch we had some presentations from SoCal Gas, San Diego Gas & Electric, and they're going to make a short presentation if you don't mind.

We have with us Herbert Emmrich here to make a presentation. Herbert.

MR. EMMRICH: Thank you very much, Commissioner and Commission staff. I appreciate the opportunity to present the views of Southern California Gas Company and San Diego Gas & Electric at this proceeding. I am Herb Emmrich, I am the Gas Demand and Economic Analysis Manager of SoCal Gas and San Diego Gas & Electric. As two years ago we also reviewed the gas assessment and we do have some comments.

Generally I want to say that the staff

did an outstanding job in making this assessment. I especially like the fact that you have scenarios because of the uncertainty that we have in gas demand, gas supply and especially in prices.

But overall the report, just like two years ago, shows demand being higher than what we are forecasting in the California Gas Report. And this is mainly due to the fact that we take into account the ten year energy efficiency goals that are mandated by the CPUC and also fully incorporate all of the renewables projections in our forecast.

In the overall SoCal gas demand forecast, as you can see by this slide, the staff is about half a percent of an annual growth factor and we have a negative growth factor. So overall the staff's report is about one percent higher than our's, which is easily within the realm of reason I would think. But it is higher.

In the residential market, again, we are concentrating our energy efficiency efforts in the residential market, especially in the low income also. The staff forecast is about .6 percent annual growth rate higher than our forecast.

In the industrial market the staff

kindly pointed out a mistake that I made. The growth rate actually is 1.2 percent, not 6.5 percent higher.

In the electric generation market, which is usually the most controversial, we show that the staff's forecast is one percent higher.

Going on to San Diego's forecast. I'm going the wrong way here, sorry. San Diego's forecast, the staff report is quite a bit higher, 2.9 percent. Generally the staff has not adjusted, I believe, the downturn in growth in San Diego, especially in the housing market. It has slowed down quite a bit.

The residential market in San Diego is about .9 percent annual growth factor higher than our forecast. Again, it is the energy efficiency programs that we incorporated. The staff incorporates only through the three year program cycle but of course we have a mandate for the full ten years with the CPUC.

The commercial and industrial forecast, we show no growth in San Diego, especially if we have concentrated energy efficiency in the commercial and industrial market. And therefore we show that even there is customer growth the overall gas demand growth will be zero.

The electric generation market, we do have a new power plant, Palomar power plant, and another one coming on, Calpine. But these plants are very efficient. The electricity that will be generated will be more than the old plants but they will use a lot less energy. The heat rate of the new plants is about 7,000 compared to the old plants that are being phased out, over 10,000.

This is the overall comparison, I won't bore you with that. As you can see across the board the staff report has a higher growth rate in all market segments. I compared it also with the a cold year and dry hydro scenario on the electric power side and it looks like the hydro assumptions may be slightly different than what we have. So the staff is being more conservative, which may be a good thing for planning purposes.

On gas supply issues. Things have not changed in the last couple of years. The Alaskan and Canadian gas is still far off, maybe 2012 to 2014.

There are plenty of resources in the United States but pretty much all of them are off-line. I think Dale Nesbitt mentioned something like that.

LNG, shale gas, tight sands gas, coal-bed methane, even coal gasification and biogas are all cost effective at these prices but they're slow to come on line.

And with LNG everybody, no matter what forecasts you look at on the demand side and on the supply side, to meet the gap between supply and demand you need LNG.

Everybody is saying that but it seems like we can't get a terminal in California approved. So our parent company is building three terminals, one in Baja Mexico, you know about Costa Azul, and two in the Gulf Coast. As far as I know they are all on schedule and the Baja facility is supposed to be operating in 2008.

I don't know what the Energy Commission can do to foster LNG coming into California. We are hoping that those supplies will be available to keep the price down. Without that prices are going to be much higher than we're projecting.

Compared to the staff report we looked at what the EIA is projecting for LNG deliveries coming out of Baja and they tend to be quite a bit lower than what the staff is assuming. Of course we have no history because these are pure projections. No gas has arrived yet. But once we have a few years of history we can probably see a little bit better on what the real forecast would be. This is fairly speculative at this time.

The facility of course is fairly large. I believe it is 1.3 Bcf so the potential is there if the LNG arrives to bring more to California. But since you have an interconnection with Baja Norte and North Baja Pipeline that gas could also go to Phoenix and not wind up in LA. Of course the interconnect at Otay Mesa with San Diego would be the first choice. That's the shortest transportation route.

Overall we expect prices to remain high throughout this forecast period, around $7 in constant 2006 dollars.

We hope that the LNG will start showing up. And then in the longer term that Arctic gas from Canada and from Alaska will actually arrive. You know, it's always another five years out and now it looks like even that may be optimistic.

The segment of the market that is pushing the demand for natural gas, of course, is the electric power market since coal is not favored anymore. If you wanted to generate all of the power with gas that is now generated with coal I don't know what the price would be. Maybe it would be up to equivalent to oil prices. It would be $10 per million BTUs. But we're hoping that LNG will arrive and keep that price down.

Of course in the long term you also have other emerging technologies such as clean burning coal, goal gasification and renewables. And that should also limit the price increases somewhat.

This is our forecast based, compared to the CEC. Our forecast is based on the CPUC approved methodology, which is looking at futures prices and then taking the long-term forecast of PIRA, CERA, the CPUC and the CEC's forecast and blending them together. This is the curve that we see right now. Prices are significantly higher in the short-term but as you see in the long-term we all seem to agree.

High gas prices, you know, impact the gas-intensive industries in California. So it is in all of our best interest to make sure we have adequate gas supplies. The ones that are most affected: the food and beverage processors; paper producers; chemicals; stone, clay and glass; and metals producers.

Just to give you a rough idea. If the price is 70 cents per therm versus 40 cents a therm that's about $1.5 billion per year of additional cost to California consumers.

Thank you. If you have questions, please.

ASSOCIATE MEMBER GEESMAN: Herb, my principal question relates to your opinion of the assumption that they used in the NARG model about the ultimate availability of natural gas in North America. Their assumption was that all of the gas would be commercially available and subject to development on an economic calculated basis. I saw your comments referenced environmental concerns and constraints to development of resources in the US. What is your judgment about accuracy of their assumption?

MR. EMMRICH: There's a lot of resource out there but most of it is off limits to development. It's even off limits just to do seismic. Dale talked about all these large fields that were supposed to be there that aren't there. Maybe they are there but nobody can even find them or be allowed to do seismic to find them.

These are in national parks or in wildlife preserves or offshore. There's plenty of gas offshore California, offshore the East Coast and offshore of Florida but that's all off limits. So we are limiting ourselves to the availability of supplies domestically.

So if you are running a model I think you have to make some kind of assumption that at least in the near term, near to medium term, those resources will not be made available.

Maybe if the gas prices are $10, you know, the politics change. But if you look at the resistance to bringing natural gas ashore in LNG form. Nobody wants any facilities anywhere. The two facilities here in California were voted down. And on the East Coast there's court fights and everything to stop LNG from coming in, you know.

We feel LNG is a very good product. It's the cleanest fuel around. Why would somebody be opposed to it? The only place it seems to be welcome is in the Gulf Coast who are more familiar with gas and oil. The infrastructure there is designed to receive it. And that's why our company, the affiliates are building two receiving terminals in the Gulf Coast. But it would be a lot more cost effective if we had one here in California somewhere.

But, you know, I am not a politician, I'm just an economist.

ASSOCIATE MEMBER GEESMAN: When did you start your career at the gas company?

MR. EMMRICH: About 23 years ago.

ASSOCIATE MEMBER GEESMAN: And what was your opinion or what were you hearing about the prospects for Arctic gas then?

MR. EMMRICH: We were actually participants in the pre-built segment of gas pipelines into British Columbia. As you remember at that time there was a proposal to build a pipeline for a mere $2 billion at that time. Now the estimates are up to $20 billion to $30 billion to build a pipeline.

But we were looking at that because we were afraid that we're going to run out of gas here in the Lower 48. So that situation hasn't changed. In the meantime LNG has stepped in. And at that time we also proposed to have an LNG terminal at Point Conception, if you remember that. And of course that was voted down by Native Americans.

ASSOCIATE MEMBER GEESMAN: Would California's interests be better served if at least the Alaska portion of that Arctic gas were brought down here by LNG?

MR. EMMRICH: The problem with having LNG come in from Alaska is that you have to, under the current law, the way I understand the Jones Act, you have to have US crews and US built ships. That basically makes it uneconomic to do so. That's why the LNG out of Alaska probably will be exported to the Far East. It doesn't make any sense to me but again, you know, that's politics.

ASSOCIATE MEMBER GEESMAN: Thanks very much.

MR. EMMRICH: Okay. Thanks a lot.

MR. TAVARES: Any questions. There's a question here.

MR. COWDEN: Hi, Bob Cowden from PG&E. First I just wanted to echo Herb's point about the commercial/residential growth in the staff report. We had found the same, similar kind of results from our studies. That the demand growth, we're forecasting a lower demand growth rate for those segments.

ASSOCIATE MEMBER GEESMAN: Did you think

the difference in your case is attributable to different assumptions about the efficiency programs?

MR. COWDEN: Yeah, I was going to say I think that's one of the main things. The other things I think are maybe in the way we deal with temperature adjusted load may be slightly different than what staff does. We don't look purely at household growth as the determinant of core gas demand.

And then kind of conversely, we have a higher EG forecast burn in PG&E service territory than does the staff report.

ASSOCIATE MEMBER GEESMAN: Significantly higher?

MR. COWDEN: Ours is about four percent over ten years, relative to the staff's 2.4 percent. You know, absent looking at model inputs it's hard to diagnose what that difference is attributed to.

ASSOCIATE MEMBER GEESMAN: Yes.

MR. COWDEN: Probably electric loads, hydro availability over that time frame, that sort of thing.

ASSOCIATE MEMBER GEESMAN: I guess with

respect to the electric generating results. It might be well advised for the staff to try to get together with the two utilities to try and better isolate what causes the differences there.

MR. COWDEN: We'd welcome that, that would be great.

ASSOCIATE MEMBER GEESMAN: I think that would be helpful to us.

MR. COWDEN: Okay, we'll work on that.

And the question I had for Herb was related to the EG demand. I think the SoCal Gas EG demand drops off around 2010, 2011 and I was wondering if your forecast had a similar profile than the staff's?

MR. EMMRICH: Yes we did have a decline because the new power plants being more efficient will generate more electricity but use less gas as the old plants are phased out.

MR. COWDEN: Okay. And I think ours is increasing because we have some new megawatts that are showing up at about the same time.

MR. EMMRICH: But I think overall the staff's forecast is reasonable. Because we don't have control over who builds power plants where. The utility can build power plants so we know those plants will be coming on line. But a lot of plants are being served off of interstate pipelines and you could have that situation. We really don't know what those plans are.

ASSOCIATE MEMBER GEESMAN: Of course as a lot of these new plants come on line the older ones retire and you do pick up a heat rate improvement that we need to make certain is accurately reflected in our forecasts.

MR. EMMRICH: Right.

MR. COX: Hi, Rory Cox from Pacific Environment. Can you discuss Sempra's current negotiations with international LNG suppliers?

MR. EMMRICH: You know, that's an affiliate and I don't deal with that but I believe somebody from the affiliates is here. Al Pak was here. I don't know if he's still here.

ASSOCIATE MEMBER GEESMAN: No, Al is still here. He's sitting in the front row smiling.

MR. EMMRICH: Because we don't handle that at all.

MR. COX: Okay.

ADVISOR TUTT: Herb, I do have one question that relates again to the differences between the staff and your forecasts. There are some differences even significant in 2006 numbers, the starting points. That can't be the energy efficiency assumptions, is that something else?

MR. EMMRICH: Well, I don't know where the staff gets their actual numbers from but our actual numbers are the actual numbers and they don't change for us. These are the filed numbers with the CPUC.

MR. FORE: Let me add to that. Our forecast is the one used in the '05 IEPR, which means it was done in '04. And so '06 is actually a forecast, not an actual number in ours. So when they come out with a new demand forecast that will change somewhat.

ASSOCIATE MEMBER GEESMAN: And the difference in the start points were an issue between the staff and San Diego in the electric side in 2005 so I think there may be a carryover of some of those methodological differences that we need to iron out for 2007.

MR. EMMRICH: We're just in the process of updating the Cal Gas Report for actuals for the year 2006. And that of course is made available to everybody so everybody should have the same starting point.

ASSOCIATE MEMBER GEESMAN: Great.

MR. EMMRICH: There are some differences, though, on utility served load versus non-utility served load that the staff may be using some slightly different numbers. But those can all be adjusted.

ASSOCIATE MEMBER GEESMAN: Yes. And we've got some time in this cycle to try and iron out those differences.

MR. SCHILLER: Steve Schiller with the University of California. My question is probably more of a process question than it might be for the Commissioner or the staff. And that's, as I have been watching this morning there seems to be a focus with the IEPR work to show a point prediction per year of supply, demand and pricing.

And I guess probably all of us could agree whatever is predicted for 2017 will be the wrong exact number. And I could see value in having specific projections, that's the official California estimate for specific price at a specific point in time.

But it would seem that what would be also very valuable would be those same graphs showing the uncertainty associated with that as would be typically shown with modeling results and a discussion of what the influences are as to what drives that uncertainty high or low and the implications for public policy. Whether it's what is happening in the Rocky Mountains or the LNG or pipeline production or efficiency programs, et cetera that's showing how that can affect different prices.

And so I guess my question is, is the purpose of the IEPR to come up with the price? You know, PG&E will pay $7.92 in 2017 for power, gas. Or is it to show that uncertainty and what influences it?

ASSOCIATE MEMBER GEESMAN: The latter. But I think much of the discussion that you may be referring to probably is based more on what assumptions are going to go into the reference case for the electricity forecast. Where we also will attempt to show a band of uncertainty.

But we have long since learned that our single point projections are always wrong and not always helpful.

MR. SCHILLER: So the work will include the uncertainties in the projections and what the influences are?

ASSOCIATE MEMBER GEESMAN: To the best of our effort to do so.

MR. SCHILLER: Thank you.

MR. EMMRICH: I do want to comment on that also. The point being, whatever forecast we show you, that's the most probable. That means it's a 50 percent chance that it's going to be higher and a 50 percent chance it's going to be lower (laughter).

MR. SCHILLER: Exactly, yes.

MR. EMMRICH: And of course for rate-making purposes, because a lot of our forecasts are for rate-making purposes, you do have to have one forecast for rate-making purposes. But there is no such thing as a wrong forecast. It is just your estimate knowing that it is going to be higher or lower out in time.

MR. SCHILLER (FROM THE AUDIENCE): But in terms of use of the information, if you use that for a rate forecast you have to have a number in that. But in terms of establishing public policy, understanding the range is important.

MR. EMMRICH: I totally agree with you. For planning purposes we do Monte Carlos, which gives us a full range of probabilities and that's what you should use for planning purposes.

MR. SCHILLER (FROM THE AUDIENCE): Thank you.

MR. TAVARES: Well thank you very much. Actually we have improved. Our probabilities are much better. We are 100 percent certain that our predictions are going to be wrong (laughter).

Anyway, with that note --

ASSOCIATE MEMBER GEESMAN: That's our motto, often wrong but never uncertain (laughter).

MR. TAVARES: Correct. By the way, if you can hold on a little bit about -- we're going to be talking this afternoon about uncertainties so the discussion will come up in just an hour, an hour and a half.

Next we have Mike Purcell and he is going to speak about supply of natural gas. So Mike.

MR. PURCELL: Good afternoon, everybody. The first thing I wanted to say is I wanted just to clear up, I think, what Herb just said. That when we talked about the resources in North America being all in play in the model, they aren't. Both coasts are shut off so they can't come into play. The east coast of Florida is shut off so it can't come into play. There's areas in the Rocky Mountains that the reserves are there but they're shut off as well because they can't come into play.

ASSOCIATE MEMBER GEESMAN: Which ones are those? It was the Western US onshore resource that I think may be confusing to me. I had understood from this morning's presentation that all of the onshore resource in the Western US was in fact considered to be available and subject to an economically calculated development schedule.

MR. PURCELL: The place I'm familiar -- On the west coast I believe that's true. But as far as in the Rocky Mountains I know there's resources that are shut off.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. PURCELL: Because, you know, it's in a national park, it's in a wilderness area, those kind of things. It's not going to come on. And there was even, you know, restrictions based on, you know, that you can only drill certain times of the day. Those kind of things were factored into the NPC work. So there is a significant amount of the resources in those areas that are shut off.

And then obviously both the coasts and the east coast of Florida are shut off as well. So I just wanted to make sure everybody understood that.

Anyway, my presentation today is just on the supply picture. Centered on California but it also deals a lot with what is happening in North America.

To start with our conclusions. In contrast to previous work that we have done we're finding now, we're projecting that the resource and supply for North America is declining. It is not increasing as is the case with the EIA forecast, the current EIA forecast, even in the 2007 AEO.

We also say that natural gas from Alaska North Slope and Arctic Canada is not going to reach into the Continental United States during the forecast period.

ASSOCIATE MEMBER GEESMAN: How long is the forecast period?

MR. PURCELL: To 2017. And really I think even in our out year times looking at this we're saying maybe 2022, 2023 for those resources.

ASSOCIATE MEMBER GEESMAN: So that is a change from what you assumed in 2005.

MR. PURCELL: Yes. And that's a major change. The big change that I think since 2005 besides the supply of resources from Canada and Alaska is that we are really showing now that LNG is going to be a major factor and a major supply source for California and for the Continental United States, North America. And I have several slides, I'll show that in a minute.

The other thing that is going to change around is we feel that gas is going to be displaced from the Southwest by LNG that is going to come in from Costa Azul. So that is going to change the equation a little bit, especially in Southern California.

We feel that supply from the Rocky Mountains is going to remain relatively constant and will have about the same volumes of gas flowing to us on the Kern River pipeline during the forecast period.

And the last thing I'll get into is just some earlier work that Bob Logan and myself had done earlier this year. Just looking at the changes in EIA's forecast and the changes in how much gas is being produced in the US, how much drilling we're doing. Just some of the trends that are going on in production in the US and Canada.

ASSOCIATE MEMBER GEESMAN: Before you change slides let me make certain I understand the implication of your last bullet there. Is it that the LNG will be priced lower than gas coming from the Southwest into California?

MR. PURCELL: I assumed, you know, I'm not -- Yes that's true because it will displace Southwest gas. So that's an implicit assumption.

ASSOCIATE MEMBER GEESMAN: So that's an economically driven displacement.

MR. PURCELL: Exactly. And I have got a table with some colors that shows that pretty well.

This is our projection from the model of the North American natural gas supply from North America, obviously, with no LNG. And you can see the big blue one is the US, the lighter blue is Canada and the yellow is Mexico. But during this time you can see that the overall amount of production is not increasing as EIA's forecast says. It's pretty flat to slightly declining.

ASSOCIATE MEMBER GEESMAN: And what's going on in Canada?

MR. PURCELL: The same thing. It's decreasing as well.

ASSOCIATE MEMBER GEESMAN: So that's not, that's not a tar sands driven reduction, that's production-related.

MR. PURCELL: Overall production, yeah. It's not -- You know, it doesn't take any away for use or anything like that.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. PURCELL: That's just gross production. The next slide just shows the US production. Again you can see there is a slight decline here. It's about five percent overall and about half a percent per year. The same places are going to be the big supply sources. You can see the yellow is Texas, the pink is the Gulf of Mexico and the light purple is the Rocky Mountains, which stays pretty constant throughout.

The next slide is the same chart as before except with LNG coming in to satisfy demand. And you can see that there's a lot of LNG going to come in to North America that we're forecasting through the period to 2017.

Here is our idea for the imports. What we tried to do is organize the legend so it makes some sense. But in the lower part are all the operating LNG terminals. Then the Nova Scotia and Baja Mexico. Excuse me, not the US but in North America.

Nova Scotia and Baja Mexico are under construction. Also the Freeport and Louisiana Sabine Pass is under construction. Then there's the two approved ones, Cameron and Corpus Christi. The South Atlantic and Golden Pass/East of River, which is another Gulf Coast LNG terminal are projected, are proposed right now.

But that's a lot of LNG. It's about 24 Bcf a day to come in by the end of the forecast period. But I think, you know, to note that. You think about, well gosh, is there enough LNG in the world. If you listened to Mr. Jensen's talk this morning his low case was projecting at 2017 about 40 Bcf a day of available LNG being liquefied in the world and his high case was well over 50, closer to 60 billion cubic feet a day. So there's that much gas that is going to be liquefied.

The question then becomes, you know, how much of it will actually come here? You know, price is going to determine that. And also, you know, the other issues that he spoke about too which were geopolitical and those type of concerns. The model runs on the economics and the economics say it should come here.

This is just the same slide except it doesn't have any of the international terminals in it so you can see we're about a little under 21 Bcf a day. And again, the majority of the gas is coming in to the Gulf Coast. And we did not in our model run this time have a terminal on the West Coast except for Costa Azul. There's not one in California, there is not one in this projection.

ASSOCIATE MEMBER GEESMAN: Are Cameron and Corpus Christi Sempra projects?

MR. PURCELL: I'm not sure.

MR. PAK: Cameron is and Corpus Christi is not.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. PURCELL: This slide talks a little bit of what we were talking about before. But you can see some of the interplay of when natural gas begins to come in to Costa Azul. And you can see here that the yellow represents the gas that we think will come in to SDG&E's system directly across the border. That will come in directly across the border is in the yellow. And then the white up here is what we believe, or our modeling anyway, that will come all the way around and come in through Topock.

But you can see that we're losing a little bit. You can see the Southwest get backed off by that. However our Rockies supply stays relatively the same. Our California production is, you know, declining but staying up fairly well through the forecast period. But it is going to change the dynamic in Southern California as far as where gas comes in and comes out.

ADVISOR JONES: So Mike, let me just clarify here.

MR. PURCELL: Sure, sure.

ADVISOR JONES: In, what is it, 2013 you have no deliveries on Blythe, at Blythe. They're backed out completely.

MR. PURCELL: From Mexico? I'm sorry.

ADVISOR JONES: From the Southwest.

MR. BRATHWAITE (FROM THE AUDIENCE): Yes. By 2013 --

MR. PURCELL: Yes.

MR. BRATHWAITE (FROM THE AUDIENCE): -- all the supplies were backed out, yes.

MR. PURCELL: Well, they will almost all be backed out.

ADVISOR JONES: Okay.

MR. PURCELL: That's the way it's coming out right now.

The next slide is -- We're getting to the end here but I just wanted to talk a little bit about US production in the main, I guess. You can see that these are the various forecasts from vintage, you know, the annual energy outlook from EIA since 2002.

And in 2002 you can see that at the end of the forecast period we were talking about well over 33 Tcf of gas. And as every year has gone by things have gotten lower and lower and now in my 2007, you know, we're only talking maybe 27 Tcf of gas at the end of the forecast period. So it's dropped quite a bit. And I think it's a reflection of what we're seeing nationally in our production trends. You know, we're drilling a lot and we're not finding that much more gas.

This slide is just to show you historical natural gas production since 1936. And you can see that gas peaked in 1971. Then in 2002 it even got, was at the all-time high and since that time it has been tailing off. But it's still relatively high. But we're drilling a heck a lot of wells to maintain this production right now.

This slide is interesting in that it shows the production from various vintages of wells and how long it took for them to produce their gas. And you can see back in 1980, this purple band, that gas took a long time to be produced. And as you can see as you move across the various vintages out to the last couple of years the decline curve is very steep.

So what that translates to is most of the gas is being produced out of wells in the first year. And that reflects that we've drilled into smaller reservoirs. It reflects that we're drilling more unconventional production, which is shale gas, tight sands, coal-bed methane. Their production falls off rapidly but can operate then at a lower level for a long time.

This graph shows the gross production in the United States, which is the orange line, since 1995 all the way through 2006. And it shows the price of natural gas in nominal dollars since then out to, you know, 2006 again, and then it shows the number of natural gas wells that have been drilled during that time.

And you can see in 1995 we were drilling maybe 8,000 natural gas wells. In 2006 we drilled over 31,000 natural gas wells. And this chart is very telling in that it shows how our production has changed and what we're drilling for. We're drilling for smaller accumulations, we're drilling for a lot of unconventional production. which again is coal-bed methane, tight sands. Those kind of prospects that just don't have the reserves behind them. And in order to maintain production we're going to have to keep drilling and drilling a lot.

The little note that is on here is because there has been so much drilling, if you really look at the losses from Katrina -- which is if you put it back in there's about maybe a half to Tcf to three-quarters of a Tcf that were knocked out by that hurricane. It's also interesting to note that in 2004 Ivan hit too so there was some curtailment of production in that year as well. So that's why I think those two years are down more than they would have been.

And if you look at the little blue arrow there that I tried to construct on this, it just kind of would show if that production was added back in where the production would be in the US. But, you know, it may mean that we're a little more level or maybe slightly up but it is certainly not a drastic improvement. You know, we haven't turned the corner and all of a sudden we're finding all this gas again.

You know, I say this then with the note as well and something that's cautionary. That just because this is happening now doesn't mean that this is the way gas production is going to stay. You know, there's technology increases.

You know, they're figuring out new ways to drill into the shale plays. New ways to fracture, new proppings to use to hold the fractures open. You know, there's people, you know, working on this very hard so there's still the possibility that production could be increased. But it's going to take some technology and a heck of a lot of money to make that happen. On our onshore resource anyway.

That's it for my presentation. Does anybody have any questions? Yes.

MR. BILLINGS: Kevin Billings with Kern River. Can we go back to your second slide on conclusions?

MR. PURCELL: Maybe. Yes.

MR. BILLINGS: Okay, I have a question.

MR. PURCELL: Okay.

MR. BILLINGS: Specifically, it kind of reminds me, your second point there, if you're going to poke someone in the eye use a big stick. From Kern River's perspective here you're talking about supply. And you say in 2009 when Rockies Express comes on line the Rockies are going to decline. And that would be gas coming down through Kern River.

MR. PURCELL: Right.

MR. BILLINGS: My question is, this morning Bill Wood shows on his pricing that the Rockies is the most competitively priced gas.

MR. PURCELL: Right.

MR. BILLINGS: And then the other point being, Kern River is fully contracted. I mean, we're at maximum capacity now on firm take or pay contracts. I guess that strikes -- the irony of that is why would the cheapest gas on a pipeline that is fully contracted not come to the California markets?

MR. PURCELL: Well, it's just -- I'm not

exactly sure and that's a good question. But what we showed on there was just that there's -- when that pipeline first came on that the production dropped about 200 Mcf a day going to, going on to Kern. And then after about 2013 or something it went back up to the normal level.

MR. BILLINGS: Okay.

MR. PURCELL: And I don't know if that's an artifact in the model. Leon may be able to address that better. But that's just the way the dynamics in the model equated that.

MR. BILLINGS: Then let me ask --

MR. PURCELL: And our model doesn't have the, I guess it doesn't have the knowledge that it is fully contracted or they have to have this much gas, you know.

MR. BILLINGS: Okay.

MR. PURCELL: Those kind of factors don't go into that.

MR. BILLINGS: All right. The next question would be, what is the source then for the production increase? Because I think everyone -- Not everyone, I'm not going to make that broad of a generalization. But a lot of people in here utilize they service of George Lippman and Lippman

Consulting for forecasting models. I'm sure the CEC uses them.

I mean, he's well used within the industry. And his models that he has show that production will increase, will continue to increase and it will out -- production in the Rocky Mountains will outpace the natural gas that will go out to the Rockies --

MR. PURCELL: Go out of the Rockies to go east.

MR. BILLINGS: -- that will out to the Midwest on the Rockies Express. So I'm questioning, where is the source for this data also then?

MR. PURCELL: Well the data that we get is again from the NPC data. You know, the various cost curves for the Rocky Mountains. So it's a function of how it's computed inside the model. So there is that production there. And it's looking at the overall production and balancing, you know, where is it going, what sources is it going to go to. And we're showing that during the forecast period that production in the Rocky Mountains does increase.

MR. BILLINGS: An increase that is

significant?

MR. PURCELL: Yes.

MR. BILLINGS: Anyway, that just, that really, really catches me off guard and I think that's a bust.

MR. PURCELL: I think, you know, it might be not as --

MR. BILLINGS: That's a bust. That's my opinion that that's a bust.

MR. PURCELL: Yeah, it could be.

MR. BRATHWAITE: Could I ask a question? When you say it's a bust, I mean, what do you mean? Okay, the Rockies Express coming on in 2009 in the model.

MR. BILLINGS: Sure, yes.

MR. BRATHWAITE: It fills up going east. It is no doubt about that. But Kern River does not lose any flows going west. In my presentation in a little while we'll show you that there is no loss of Kern River flows during the, during the forecast period.

MR. BILLINGS: But that's not what that was saying.

MR. PURCELL: Yes, because it drops about --

MR. BILLINGS: That's saying that Rockies production declines.

MR. PURCELL: -- about 200 a day during the forecast period. Right there.

MR. BRATHWAITE: Well then I'll take a second look at that, okay. I'll take a second look at that.

MR. BRATHWAITE: Yeah, I would just appreciate that. You know, that's --

MR. BRATHWAITE: But overall though, overall Kern River does not lose flows during the forecast period. I mean, we may have some little dips up and down, I'm not going to, I'm not going to argue about the blips. But in terms of like the overall it does not lose any flows coming west. I hope that answers your question.

MR. BILLINGS: Yeah.

MR. PURCELL: Yes Al. I'm sorry, I didn't -- I wasn't looking, go ahead.

MR. COX: Rory Cox from Pacific Environment. Now you mentioned that the Southwest natural gas was going to be, was going to be competitive with the LNG and that would decrease Southwest supplies.

MR. PURCELL: Right.

MR. COX: But isn't it also -- I mean, what role does the -- The Public Utilities Commission in 2004 passed a ruling which allows SDG&E and the gas company to not re-up those Southwest contracts to make room for the LNG. So given that they have that regulatory permission to not buy Southwest in favor of the LNG what role does price competition really play there?

MR. PURCELL: Well in our model none of those legal or -- those type of constraints aren't in there. So it's just a matter of this is the price that's driving that. So we don't have a factor in there I don't think. Is that not true?

MR. BRATHWAITE: Let me, let me answer this one.

MR. PURCELL: Okay.

MR. BRATHWAITE: It is true, we cannot directly take in consideration any sort of legal constraints that may be placed upon production or anything like that. However, if we believe or if there is some information that comes to us that have us believe that something will be delayed in terms of its construction or in terms of its flows or anything like that we can make it that the -- whether it's a pipeline, whether it's an energy terminal or anything like that, we can make sure that that does not flow until say maybe 2015, maybe 2020 or something like that.

A good example of that, I think Commissioner Geesman was asking about this a short while ago, is the situation with the Alaska pipeline. Now in 2005 we thought this was going to come on in 2013 and 2016 for those two pipelines up in the Arctic.

Since then we have reevaluated, we have looked at it, we have spoke with some of the industry folks, and we have now put that off until 2020 and 2022 and we're not even sure it's going to come on even then. But the fact of the matter is it is now outside our forecast and our forecast horizon.

So in terms of putting constraints in the model we can do so without directly dealing with the issue that you just raised. I hope that answers the question.

MR. PURCELL: We haven't done that.

MR. BRATHWAITE: On which one are you talking about?

MR. PURCELL: His issue with those supplies in the Southwest. We haven't put that constraint in the model right now.

MR. BRATHWAITE: No, not right now but it could be done.

MR. PURCELL: Right, it could be done but it is not there.

Dale, do you want to -- go ahead.

DR. NESBITT: Go ahead.

DR. ARTHUR: Dave Arthur, City of Redding. To sort of pick up on that theme a little bit.

It seems to me that if we're going to have 24 Bcf at the end of the period that represents a meaningful percentage of US supply. And from this morning I learned that Russia and Iran are a predominant source of supply and probably even more so in that type of time frame. I'm not sure that's right but that seemed to be what one of the charts was suggesting. So that would suggest that political considerations might be fairly significant.

And so my question is, since we have an illustrious history, not simply in California but throughout the West and even North America of having political decisions having pronounced impacts on economic models, is it possible to run

politics as usual in your model so we understand
how politics might cause disruptions that we
otherwise weren't predicting for what economics
would tell us?

MR. BRATHWAITE: The answer to your question is yes, we could run politics as usual and we could run dangerous politics or we could run whatever politics you wish to run. The point is though, if we believe --

For instance you just raised the issue of Iran. If we believe that Iran is not going to be supplying any liquefaction capacity to the world we could shut it off. And that would be, that would be the politics, taking the geopolitical uncertainties and putting that into consideration in our model. That could be done.

The point is though we just have to develop the scenario to deal with whatever issues that you or anybody else in our audience might choose to raise.

MR. PURCELL: Dale.

DR. NESBITT: Dale Nesbitt, Altos.

On this question of price competition. Let's go away from the model and go to the real world, although I agree there is not much difference. Now, how does the real world work on price competition? There is a price. There is a price and everybody is a price taker. And if you put more into a market the price goes down but you're still the price taker.

And so this issue of price competition between Southwest gas and LNG really isn't very complicated. There's a price a Topock. Whoever can make profits at that price produces and sells and whoever can't, doesn't. And so the issue --

The other issue in Rocky Mountain gas, which has gotten a lot of attention recently because I don't think people understand Rocky Mountain's gas as well as we should. The point Kevin made is that Rocky's is the cheapest gas on the continent. I don't think people believe that in general in the industry.

The Rockies gas, you have tight formations in the Green River Basin, you have the Uinta Basin gas. These are very tight. The fields are one Bcf or less. If you ask Anadarko Petroleum who publishes estimates all the time they talk about the full cycle production cost of Rocky Mountain's gas exclusive of reserves today at $8. So it's not clear what the production cost of Rocky Mountains gas is.

If we use oil as an analogy, think about oil. Nobody really wonders why it is that domestic production is only 40 percent of the total. It's because that's all the oil you can get out of the ground at 60 bucks, that's why.

And that's kind of the simulation that these guys try to do here is to say, let's take that same model. Not that it's the real world but it gives us a nice economic benchmark for a base case. And talk about cost-on-cost competition in a world where the price is set by gas-on-gas and gas-on-oil competition.

So don't read more into it than that. It is just an economic reference case that was used to put together four scenarios and to really Start thinking about these uncertainties. Because the minute we think we're certain about Rocky Mountains gas production costs I'm pretty sure we're uncertain.

MR. PURCELL: Thanks.

MR. PAK: Al Pak for Sempra LNG. I have a correction that I can offer you and a comment. And it was really helpful to go after the last speaker because he pointed out some kind of a -- I think part of the question that I have for you following the correction has to do with the market anomalies that get displayed in the tables and charts that you have provided.

First of all, the correction. The Cameron facility is not only approved, it's under construction. It's completion lags the Costa Azul facility by about eight months so our expectation is that sometime either September or fourth quarter of 2008 that facility will be fully operational and available at 1.5 Bcf per day. We recently got a permit change approved by the FERC that upped the capacity, available capacity at that facility and we're constructing to that limit right now.

ASSOCIATE MEMBER GEESMAN: Do you have one other Gulf Coast project?

MR. PAK: Yes, and I was going to say that's the other thing I want to add. We have the Port Arthur facility that recently received its FERC certificate and the final investment decision on that project is pending our -- We are currently marketing the capacity at that facility. And the minute we hit what we consider acceptable levels of contracting, forward contracting on the capacity we'll go ahead and commence construction there.

The question I have, I think, as I said the last gentleman addressed this. When we look at the flows from the LNG facility at Costa Azul to Blythe in the years 2010 and 2012 those supplies according to the model aren't flowing. That also happens to coincide with the price projections that Bill Wood provided this morning.

So the sawtooth pricing that you saw as price falls in 2010 apparently the model is representing that Costa Azul supplies will not flow north to Ehrenberg. And the same thing happens, the price rises in 2011 and apparently we flow according to the model. And in 2012 that flow induces another price decline and we're shut out in 2012. I think, you know, if there is a way to do this --

And I'm kind of asking if what I'm saying is correct? Is that just a model anomaly and can it be corrected just in the narrative of the modeling results that that's actually marketing contest? We consider that to be a contestable market.

We don't expect the Baja Norte and North

Baja pipelines to be dry in the years because San Juan or Topock or, I'm sorry, Permian, we get a lower price and we're out of market and they're in. I think that's all contestable market and I think it's represented better in the out years than it is in the early ones.

But because we saw the price fluctuation and the flow fluctuation coinciding with one another we don't want to have the state representing to the Legislature and the Governor that Costa Azul is the swing facility. We don't expect that to be the case.

MR. BRATHWAITE: Yes. I fully accept your comments here. The point, the point I wanted to make is that these are all preliminary results. That problem that you so rightfully point out is correctable and will be corrected.

I must admit that right now during this process we are quite pressed for time in terms of getting this thing put together. There are certainly some, shall we say, bumps in the road that need to be leveled out and straightened out and I promise you it will be so corrected.

MR. PURCELL: Anybody else? Thank you.

MR. TAVARES: Well thank you very much.

Leon is going to make a presentation on the infrastructure. I think Commissioner Geesman had a question this morning so go ahead and start your presentation and Commissioner Geesman, whenever you have --

MR. BRATHWAITE: Good afternoon. I'm Leon Brathwaite, I work in the natural gas unit upstairs. I do most of the modeling work around here. So any problems with the model, our modeling work, it's my fault. No, that was a joke. That was a joke, it was a joke.

Okay, I am going to talk about the infrastructure and some of the results that came out of the model in some of our work. What I will present will be California-centric. There are a lot of issues outside of California that I will not present.

Some of the issues have already been spoken about by Bill this morning in particular and some of the other issues that we saw early on this morning. So I will not repeat them here but they are certainly relevant to our discussion.

Okay. So what I'll first talk about, the major findings, and then we'll look at some particular slides just to show what these major findings say. Okay.

During the forecast period nearly all major pipelines will operate below 100 percent capacity factor. Kern River, however, hovers around 80 percent to 85 percent capacity factor.

Now I want to put this in context. Kern River delivers a substantial amount of gas upstream of the California leg of the pipeline. They deliver a lot of gas in Southern Nevada to some of the power plants there. So they deliver the maximum amount of gas, even though it's only 80 to 85 percent of the capacity that comes to California.

They are delivering the maximum amount of gas that could be delivered to California right now. So I just wanted to put that in context. It does not -- I was not intended to mean that Kern could deliver more gas if so called upon.

ASSOCIATE MEMBER GEESMAN: So where do you lose the 200 million cubic feet per day from the Rockies?

MR. BRATHWAITE: Two hundred million cubic feet per day?

ASSOCIATE MEMBER GEESMAN: It was in Mike's presentation.

MR. BRATHWAITE: Well I would imagine that's probably a little bit upstream at some of those power plants. There are severe there about, I don't know how many. Kevin, how many power plants do you have upstream of the California leg?

MR. BILLINGS: Kevin Billings, Kern River. Kern River provides natural gas service to eight large natural gas-fired power plants in Nevada and then two in Utah.

MR. BRATHWAITE: Okay, thank you, thank you.

MR. BILLINGS: And just to be specific about that, the other subject. Kern River delivers approximately 85 percent of the natural gas consumed in Southern Nevada. So it is being siphoned off before it gets to California is what Leon is saying.

MR. BRATHWAITE: Thank you, thank you. Okay. So all other pipeline systems, other major pipeline systems that serve California hovers around 50 percent. In some cases falls below 50 percent, as you will see shortly.

LNG entering California displaces traditional natural gas supplies from the Southwest. Now I want to be clear about this.

The LNG that is entering California, it is an estimate that we have. Because when that gas gets around the horn and gets back to the Blythe-Ehrenberg area. There are several options as to the way it can go so we are just making estimates as to what will actually enter California.

Okay, the assessment projects that only two pipelines affecting California will expand. These pipelines are TGN, which travels between Mexico and San Diego, and the North Baja line.

After Costa Azul comes on line both of these pipelines will expand to accommodate the flow of regasified LNG. TGN will reverse and instead of going south will now go north into San Diego and North Baja instead of going west will now east and deliver gas into Blythe/Ehrenberg.

Okay, capacities and flows at the California border. Here we see what is happening at Malin. We see that the capacity utilization starts off around 60 percent or so and then sits around the 50 percent line, declining slightly in the outer years at the end of the forecast period. By that time we are looking at about 40 to 50 percent capacity utilization at Malin.

This is Kern River. And you see the

Kern River capacity utilization hovers around 80 to 85 percent. And again keeping in mind the comments that was just made by Kern River that this is all the gas that an be delivered at this point in time given their upstream commitments. So Kern River has no more gas to deliver into the California market. So they are, probably you can say probably fully utilized at this time.

ADVISOR JONES: Can I ask a question about the last graph?

MR. BRATHWAITE: Yes. This one?

ADVISOR JONES: So what accounts for the dips like in 2011, 2013? It's not even throughout the years.

MR. BRATHWAITE: We do have some price variations that occur throughout the forecast horizon. And as prices change a little bit along the way you see these changes in flows and supply as the price differentials change and you see these sort of changes.

Also in light of that Kern River also does some deliveries, substantial amounts of deliveries upstream of this measurement. So between those two things, yes, we do see some of these dips occurring as you go through the forecast horizon.

But you will notice at the end of the forecast horizon we are up well over, they are probably all 90 percent. But you will see the blips during the forecast period, yes.

Okay, this is what is happening at Topock. At first capacity utilization rises at Topock but then falls off and falls below 50 percent by the end of the forecast period. And this is gas out of the Southwest. A lot of this displacement is -- a lot of the reduction in capacity utilization is the result of LNG flows.

And here we see what is happening at Blythe/Ehrenberg. And this goes to the comment that was made by Sempra about the zero flows in 2010 and 2012. I will correct these things and stuff. But what this graph does show though, it does show, is the LNG coming in and displacing Southwest flows. This is what is really happening here. You see Southwest flows dropping off substantially, eventually reaching zero, and LNG is taking its place in the outer years.

ASSOCIATE MEMBER GEESMAN: And the only other LNG you assume on the West Coast is Costa Azul?

MR. BRATHWAITE: That is correct, yes.

ASSOCIATE MEMBER GEESMAN: Costa Azul at its current plan size, no expansion?

MR. BRATHWAITE: There will be expansions around 2013. But in the early years, yes. Between 2008 and 2013 at its current capacity design.

ASSOCIATE MEMBER GEESMAN: If LNG is winning a price competition in your model with Southwestern gas, it looks fairly soon, wouldn't the economic nature of your model snap its finger and have another terminal?

MR. BRATHWAITE: Commissioner, one of the things that I do note exactly in the model, and this is not presented here, is that once Costa Azul comes on that thing fills up almost immediately. So the answer to your question is yes. As a matter of fact, if I allow that model to go as it so pleases economically, for want of a better word, yes, we will have more terminals in the Mexico Baja area, yes.

ASSOCIATE MEMBER GEESMAN: But you haven't incorporated that into this model?

MR. BRATHWAITE: No, it is not incorporated.

Okay, the overall supply outlook for California. What this graph shows is the decline in Southwest flows occurring in this area and the expansion of LNG flows occurring up here. That is the main point of this graph. Everything else seems to hold its current, it's current percentage. There is some variation of it but the main two things is to look at what is happening in the Southwest in this area and what is happening to LNG in this area up here. So this is the main point of this graph.

This takes me to the end of my, of my presentation. However, there are a couple of, two points that I would like to make that are relevant to infrastructure. One being the construction of the Rockies Express which comes on in 2009. That was already mentioned. That takes gas east. That does have some effect upon the overall supply and demand outlook in North America. The Rockies Express does fill up once it comes on in 2009.

The second thing is the substantial construction of LNG facilities in the Gulf of Mexico in particular. And there too we are seeing quite a lot of activity in terms of LNG flows and regasification occurring in the Gulf of Mexico.

But that's about it. But those things were mentioned previously so I didn't put it in my presentation. So I'll take any questions or comments you may have right now.

ASSOCIATE MEMBER GEESMAN: Just to confirm what was said earlier, no Alaskan or Arctic Canada gas during the forecast period comes into the Lower 48?

MR. BRATHWAITE: That is correct, Commissioner. As a matter of fact in the model we don't allow that to even be considered to be available. Alaska is available, I believe, in 2022 and the Mackenzie Delta Pipeline is available in 2020. So it's all there.

MR. YEE: I'm Gary Yee with the Air Resources Board. My question relates to gas quality and the issues that are pertaining to the South Coast Air Quality Management District's position in terms of importation of LNG with higher energy content. I know there has been some discussion, recent discussions/negotiations with SoCal Gas regarding the bringing in of that natural gas and accommodating to ensure that it does not raise the historical average above their 1360 Wobbe value.

Now in your presentation here you're suggesting that 1.5 billion cubic feet of LNG will be brought into the system. That seems to be a lot of gas. And if this is higher energy content, higher Wobbe content gas, I don't see how that is going to be accommodated for.

MR. BRATHWAITE: Okay there are two things I would like to make, two comments I would like to make pertaining to your question.

Number one, we allowed TGN, which reverses and flows north during our forecast horizon, we allow it to expand as it so wishes. And we are going to be taking a second look at that to see if that assumption is valid. I think Bill Wood, my colleague, will tell you that it probably should be kept and limit the amount of LNG that flows into San Diego. So that may address part of the amount, part of the issue in terms of the amount of LNG that comes into Southern California.

And secondly about the gas, the gas quality issue. We did not really and truly take that into consideration in terms of developing this case. However, there have been some comments by some of the stakeholders that this is probably a sensitivity or a scenario that we should truly consider running. And in consultation with the Committee on the natural gas and the IEPR Committee we will be taking that into consideration. Maybe running that scenario and seeing what effects that will have on the whole, on the whole infrastructure makeup of the state.

MR. EMMRICH: I did want to respond to that comment. If there is 1.1 Bcf of gas at the Costa Azul plant, 400 million could go to San Diego, 300 million a day will probably stay in Mexico and the remaining 300 million would wind up at Blythe where it could go Phoenix or into LA. The amount of gas hitting our system we anticipate to be fairly small unless that facility is really expanded into the second phase.

MR. BRATHWAITE: Thank you.

MR. PAK: Al Pak for Sempra LNG. Looking at the flows from Costa Azul into the San Diego system. We had an off-line conversation where the staff agreed that a mistake had been made in the representation of the physical capacity of Otay Mesa. It is at present being constructed to 400 million cubic feet per day. And that is largely the result of the CPUC's ruling that new shippers would have to pay for incremental costs of pipeline capacity and receipt point capacity and we've done that to the level of 400 million a day.

In keeping with this idea that the final reports will include stochastic and heuristic analyses, and if I remember correctly from my college statistics courses that's sort of Latin and Greek for futzing around with the input variables. We kind of like the idea that this should be one of the scenarios that should be included in those analyses.

We have had a lot of discussions with the Public Utilities Commission about the rate payer benefits that could take place on commodity if investment of capital, if capital investment at the Otay Mesa and downstream facilities were to be made and paid for by rate payers on a rolled in basis. And we think that the analysis that resulted from this mistake, which we sort of considered a good mistake, is indicative of the kinds of things that we were seeing as we were nominating to our affiliated gas utilities the level of capacity we might be interested in building there.

The price collapse that you saw in the San Diego system relative to the SoCal system and in Southern California relative to Northern California I think are the kinds of results that could be instructed as to whether California's current policy on incremental rate making for new facilities is the right one or whether a rolled in rate making policy should be reconsidered. And the PUC has held open the possibility that that would be done.

I heard Bill Wood say this morning that he saw the mistake and he was going to correct it and that should absolutely be done for the reference case. But if you're going to run stochastic analyses this is not a bad one to keep in the lineup of scenarios that you have. So that's the only comment we had there.

MR. BRATHWAITE: Maybe, Al, it was not a mistake right?

MR. PAK: That's right.

MR. BRATHWAITE: No, it's a joke, it's a joke.

MR. COWDEN: Hi, I'm Bob Cowden, PG&E. I noticed with, you know, once Costa Azul comes on line, flows on PG&E's Redwood Path are kind of in the 800 to 900 a day level.

MR. BRATHWAITE: Yes.

MR. COWDEN: And even though you indicated there wouldn't be an expansion it seems like there just has to be a lot of pressure on PG&E's southern Baja path. And I'm guessing that in your model that that path flows at a fairly high load factor after Costa Azul comes on. So I think even though the model may not want to expand the pipeline it is likely that there could be a lot of interest from our shippers in expanding the line if it is flowing at a real high load factor over a Bcf a day.

MR. BRATHWAITE: Absolutely. Yes I totally agree.

MR. COWDEN: It would be nice to be able to break out maybe some of the capacity factors on some of the lines in California in the report just to see how much loading there is on the lines in the Southwest.

MR. BRATHWAITE: In the final report I'll certainly make sure that is done, Bob.

MR. COWDEN: Okay, thanks Leon.

MR. BRATHWAITE: Sure. Questions, comments? If not, thank you very much for listing to me.

MR. TAVARES: Thank you.

Commissioner Geesman, if you don't mind we can take a few minute break.

ASSOCIATE MEMBER GEESMAN: Yes. Why don't we come back at five minutes after three.

(Whereupon, a recess was taken off the record.)

MR. TAVARES: We wanted to reconvene again. We already made all the staff presentations. Next we have one of our consultants that is going to help us improve our 100 percent probability of being wrong. Maybe we can go out to 125 probability (laughter).

She is going to discuss the uncertainty of alternative scenarios. So Catie, why don't you just go ahead.

MS. ELDER: Sure. And I am not going to probably fix that uncertainty or reduce the probability of being wrong, I'm just going to tell you how mammoth it is.

I want to acknowledge first, on the phone listening is a colleague of mine, Dr. Youssef Hegazy, out of our Seattle office. He has worked with me primarily on the demand associated with this as well as the price. He worked on the oil/gas price relationship stuff that you'll see in the presentation.

Youssef was supposed to be able to interrupt me if he needs to and we hope that's true. So if you hear this voice coming from nowhere, this sort of soft-spoken voice coming from nowhere, hopefully that's Youssef Hegazy trying to interrupt me and make a point.

DR. HEGAZY: I'll try not to make it so soft.

MS. ELDER: There you go, it works. Great, I'm glad to hear that. Now I have to figure out which button to push. Page Down is not working. Arrow, Down Arrow. Okay, now we've got it.

RW Beck joined this process to work with the staff probably in, I don't know, early to mid-March. And the role that we were given was to try to help staff, in essence as the bottom bullet down there on the page, to think outside the model. So traditionally what the gas unit staff has done in putting together its natural gas assessment is to really prepare a point forecast.

They recognize that that doesn't deal

with uncertainty. We've tried to give them in the work that we have done some ways of thinking about uncertainty to try to move away from a reference case where we say, this is our forecast, but instead staff puts a reference case on the table that all of you can use for thinking about how the world might work.

And the alternatives that we crafted and put forward to go alongside the staff forecasts are really designed to add more fuel to the fire for that thinking process about what could happen versus what will happen.

There are two things if you were going to ask me, what are the two key things that come out of staff's work. And what I would tell you is the two bottom-line, fundamental findings that ought to be uppermost in your mind are that you see a lot of LNG coming in to meet US demand. And the reason for that fundamentally in the model is the model is saying that it's economic for that to happen. That's really important to understand.

The second thing is that the basis differential to California, and to a degree the West, the Western base is narrow so it doesn't actually flip but the basis to California flips completely. So that instead of California receiving a discount to Henry Hub prices we begin to pay a premium. And what you see in the rest of the West is that the basis differential narrows substantially.

So if you go back to the table that had a whole bunch of columns for different basis points and years that Bill Wood had in his presentation you see the negative basis out of the Rockies and the negative basis out of AECO narrows substantially relative to California. When you add transportation costs to that, by the time it gets to California we're going to pay a premium. Those two key things are really important.

Now Youssef had a lot of experience in modeling. I probably have a fair bit of experience, one could probably say over a 20 year period in the natural gas business in and out of models. And we were asked to make some comments about NARG and the World Gas Trade Model.

And, you know, there are things that have to be recognized kind of on both sides. There's a lot of things that the model does really well. Bill Wood talked about how it gets the basis differentials right. That's really important to recognize.

The other thing is that it correctly, we think, accounts for the expected future shift in the physical elements of the market structure.

Then it takes demand and supply and it matches them up and it computes price where price is the rationer, the arbiter of the market in essence. It makes supply and demand equal. Where they are out of balance price rises so that demand exits the market and new supplies produce so that everything equilibrates. Those are important things to understand about the model.

But the way that the model has been used, for better or worse, is really to produce this point forecast that we've talked about. And so what we are trying to do is give folks some ways of thinking outside that point forecast.

Another point I can make about it is that means that it is really hard to run a lot of sensitivity analyses. Staff to date has run four. If you let some of us, me and the staff combined go wild with the kind of sensitivities that we'd love to be able to run, that number probably expands pretty quickly within probably five or ten minutes of discussion to 20 or 30. And I'm sure that to assess a full range of uncertainty we'd be talking more than 100 different scenarios. And doing that is just not practical.

ASSOCIATE MEMBER GEESMAN: Let me ask, Catie. What's practical? Or how do you define practicality?

MS. ELDER: How much money do you want to spend to resolve the uncertainty?

ASSOCIATE MEMBER GEESMAN: I'm of the opinion we spend millions and millions and millions of dollars anyway. I don't know what we spend it on. I don't always know of what value it is. Why shouldn't we have modeling tools that lend themselves to running multiple scenarios rather than investing so much in building some kind of Maginot Line that provides us a single point.

MS. ELDER: That's a very good point. And I think that --

ASSOCIATE MEMBER GEESMAN: I'm not expecting a contractor to respond.

MS. ELDER: Right, right.

ASSOCIATE MEMBER GEESMAN: But certainly the staff people in the audience, I think it's something that bears quite a bit of thought. I think it would be of greater value to state government to have more scenarios rather than fewer, even if there is a sacrifice in depth that goes along with that choice.

MS. ELDER: I suspect, Commissioner, there's a lot of folks in this room who'd agree with you. I think I do and I think a lot of -- Leon is holding up his hand. And if Youssef could get a word in edgewise I'm sure he'd agree too.

DR. HEGAZY: Yes.

MS. ELDER: That was a yes.

Let's talk about demand a little bit. The range of uncertainty, the way that we articulated the range of uncertainty around demand. We worked out two different approaches to try to help the Commission understand the range of potential variation in natural gas demand around the reference case.

The first one uses the variation in historical demand growth and creates a statistical distribution, standard deviation, around that historical demand growth. That would then do some Monte Carlo draws out of and create basically an expected case demand forecast and a 90th percentile case and a 10th percentile case. I'll show you what those look like. They're rather astounding.

The second approach that we took, and this is delineated in detail on a subsequent page that I'll show you, it's also in the report, we listed the factors high, low or around, but above and below, that we thought would create higher versus lower demand. And you can change that list.

The real point of trying to take the quantitative approach versus the bottoms-up approach that is in the more detailed list of factors table is that we don't really know what might create, at the end of the day, higher or lower demand. We've got some ideas that might.

But by just taking the quantitative, statistical approach we don't have to worry about what those factors are. We can just say, hey look, we know that demand varies by a lot. And we can incorporate that into the demand forecast without having to worry about what it was that made demand higher or what it was that made demand lower.

The other thing that we did is that we benchmarked staff's demand forecast against EIA.

Now not because we thought EIA was right. That's not why we did it. We did it because it's obvious, it's out there, it's published, lots of people look at it to see what it is. A lot of people have it in mind as to what it is. It's easily available. So we'll show you our comparison of the staff's demand forecast versus what EIA's has got.

And I think that shows up in the next graph if I'm not mistaken. There you go, there it is. The black line is staff's NARG reference case and the other lines are all of EIA's demand forecasts. The blue one is EIA's reference case, the gray is their high, the magenta or pink color is their low.

Now if you go back a page, and this is my intent, to make sure that everybody is dizzy, is that you see the staff's demand forecast is really similar to EIA's in the first couple of years. There's not a lot of difference actually between EIA's high and low versus its reference case in the first couple years versus staff's case.

The real differences occur in those out years beginning by about 2011 on out through 2017.

You see that staff's demand case is about a trillion cubic feet higher. I'm sorry, two trillion cubic feet higher than EIA's. The reason for that, Dale talked about it earlier. He talked about the cap and trade elements and emissions limits, allowances that are captured in his electric demand model. That's why this demand forecast is so much higher than EIA's.

ASSOCIATE MEMBER GEESMAN: But even there I would say based on the discussion we had this morning you may very well be arbitrarily constraining that same dynamic in the Western United States where it might appear that California policy is driving the shift away from coal at an even more rapid rate than is likely to occur on the eastern coast.

MS. ELDER: That is absolutely right. There's a question about whether or not the demands that we have for the West is high enough at this point.

DR. HEGAZY: One thing we did in our own was to compare the EIA forecast for electric gas demand versus ours. Ours, that's RW Beck. What happened is EIA, they delivered their forecast probably early in 2006, maybe at the end of 2005, and there were several factors that affected their outlook on the electricity demand for gas. One of them is the capital cost for coal, which at that time was a lot lower than what it is right now.

So when we ran our model the model did not take more than probably five, six percent off additional coal generation for the next 20 years in the entire United States. For EIA they expected around 55 percent of the new capacity additions to come from coal. Most of those were in WECC in the west and the southeastern part of the United States.

That is what we found that is the most dramatic change, the most dramatic difference between our assumption and their assumption. And I believe that the electric gas demand that came from the Commission also had the same assumption that we had.

MS. ELDER: And Youssef, when you mentioned coal cost you were talking about construction cost?

DR. HEGAZY: Right. The capital cost of adding a coal power plant. Over the last 18 months they have increased from around $1500 a kilowatt to $2500 to $2800 a kilowatt. So it's almost doubled. That's a major factor in coal. And in addition to that the known fact that the regulation or legislation on CO2 production is lowering in the future.

MS. ELDER: And we should tell you that where those construction cost numbers come from, they're coming from our independent engineering colleagues who are working on coal-fired power plants. Right, Youssef?

DR. HEGAZY: Right. And actually also you can look at a lot of the IRPs, integrated resource planning, that has been filed by major IOUs around the country. You will see the same, the same figures in the most recent ones.

MS. ELDER: Okay. I mentioned earlier how Youssef actually constructed the demand case. In essence he thinks of demand as growing at some rate with an error term around it. So we've got the growth rate that comes from the model projection. And then what we used, we used historical demand and the rate of change of growth in historical demand to create this distribution or this disturbance term, this distribution that the disturbance term is drawn from via the Monte Carlo simulation. At some point I'll get the words out of my mouth correctly.

We just wanted to make sure we had at least one equation in here to torture you with in Youssef's section since I've got a couple.

The results of that are what you see on this page. The blue and the black line that are in the middle there show you staff's expected demand forecast, also shows you the random draws, the expected case that comes out of our analysis around that. But then the gray line and the pink line are the ones that are interesting. Those are those 10th percentile and 90th percentile demand cases.

And what you see here, and this is sort of the critical thing to notice is that at the beginning of the forecast during 2007 the differences between those numbers were about half a trillion cubic feet a year. So two cases that capture kind of the biggest range of the universe around the expected case are roughly half a trillion cubic foot higher than and lower than the expected case.

By the time you get out to the end of the forecast period that gap or that range widens to be almost two trillion cubic feet. So we're talking about a difference potentially when you think about the distribution that captures all of the uncertainty and demand. That demand could be two trillion cubic feet higher than we think or two trillion cubic feet lower than we think. And that's a huge, just a huge number.

ADVISOR JONES: Catie, while you've got that chart up. It shows more here than it did in the earlier graphs. The sort of blip up in demand between 2011 and 2013.

MS. ELDER: Right.

ADVISOR JONES: And you guys are investigating that or do you have a cause for that?

DR. HEGAZY: Let me just explain what that graph is because this is not a -- The demand growth is not our forecast.

ADVISOR JONES: Okay.

DR. HEGAZY: What we are trying to show here is, if you remember what one of the earlier slides that Mr. Fore has shown here in the morning in which he was talking about the elastic part of the core demand, in which demand is a function of gas prices and then population and then GDP and other factors like that.

Each one of those factors are random in nature. When you assume GDP is going to grow at three-and-a-half percent for the next 10 or 15 years this is a very strong assumption. So what we are seeing here is over the history that three-and-a-half percent has a distribution around it. It was one year at five-and-a-half percent, another year it was one percent and maybe another year it was almost zero.

So including that distribution for population and distribution for GDP and for all other parameters in the right hand side of the demand equation is the way that we suggest to do in order to -- and running a Monte Carlo simulation on 100 cases for each, in order to come out with a probability distribution of how the growth of demand, say for the residential sector or industrial sector, should look like.

Now when you do that randomness there is two different ways. One is a simple Monte Carlo simulation and the other one is called, and bear with me with this name, is Latin Hypercube, in which you look at the distribution and divide it into areas. And you make sure that you're drawing consistently from the area that you think has higher probability. You're drawing more from the area that has higher probability and you're drawing less from the area that has less probability. And that's what we did in the last run.

Before that when you just did a raw run of the case, one of the runs or two of the runs might come from the tail end of the distribution more than they should and they create that bump that you have seen there in your graph. I hope everybody is still with me.

MS. ELDER: We're all here with you, Youssef.

DR. HEGAZY: Okay. Did that answer your question?

ADVISOR JONES: That was fine, thank you.

MS. ELDER: It does partly but I think we need to go back and we need to look at whether or not there is a blip, an upward blip in demand in the reference, in staff's reference case number in 2012 or whether I mislabeled the lines.

Here is table that lists the different variables that could create a higher growth case for demand versus a lower growth case for demand.

You can see they revolve around things like efficiency policy, conservation policy, carbon reduction, which we've spent a little bit of time here talking about. The impact that that has on coal-fired generation.

Demand could be lower, on the other hand, if folks decided that they wanted to build some nuclear power plants instead. The impact of renewables arguably should be to reduce natural gas demand. Natural gas demand might be higher with higher economic growths.

We mentioned hydroelectric conditions because we know that they have a big impact here in California, particularly in Northern California on the PG&E system. Although they should be temporary impacts, we would think, at least in the short term, unless we actually see the snowpack totally melt in the Sierra due to global warming.

And then electric transmission issues could have an impact on natural gas demand if we are constrained on capacity expansions. For example perhaps the Palo Verde Devers line that was denied last week by the Arizona Corporation Commission. Then perhaps that means we have to deny more electricities and natural gas here in

California, so all of those things could have an impact high and low.

And I'm sure many of you could add to this list on both sides what the high side and the low side --

ADVISOR JONES: Catie, in terms of the hydro conditions. If you go back to the supply that was forecast out of NARG you show Blythe to be zeroed out. So that means it is not being used at all for a three or four year period but then there's an assumption that it comes back on. In reality would a pipeline company keep that line available just betting that there might be some use down the road? And what does that do in the case of having low hydro conditions where you are much more dependent on gas?

MS. ELDER: That is a question that probably deserves more than a 30 second answer I'm going to give you. It's probably a four or five page long discussion. But let me talk on a couple of things to think about.

We actually have seen historically, within the last 15 years we have seen some pretty low flows on the El Paso system into California. And despite those low flows the pipeline did remain in place and available so that when demand did increase we were able to get additional gas supply over that pipeline. Now what happens in the future is kind of a different question.

If in point of fact the impact one could imagine, I'm not saying that this is what the model projects or what the model results even show, but they sort of give you a glimmer of this idea. As Costa Azul begins to deliver gas some of that gas moves eastward on Baja Norte and then up towards Ehrenberg-Blythe then some of it could come into California. Some of it could ostensibly flow via displacement back to Phoenix. Perhaps El Paso decides to physically reverse the flow of its southern system so that gas can flow towards Phoenix. Any of those things are possibilities.

And I think it's really hard right now to predict which one of those would happen. But as you rightly point out, we need to keep them all in mind. So how is that for the quick answer?

ADVISOR JONES: That's great, thank you.

MS. ELDER: Recognize that it's a complicated story.

This is a picture. Mike gave you the picture earlier in his presentation, the color picture, but I had this notion that I had to put everything in black and white for the report so I put everything in black and white. Or most everything at any rate. So this graph is trying to recapitulate what Mike Purcell told you about the supply forecast of the reference case.

And here is a really key thing that I wanted to use this to remind people of and that is just the massive, the massive increase in LNG that comes into the US in order to meet rising natural gas demand. You see the bottom of the bar is really domestic production and that number kind of bobbles, if you will, around 18-and-a-half, maybe 17 trillion cubic feet a year depending on the year. And then we get some gas from Canada.

That number shrinks by a little bit you can tell. That's the diagonally colored part of the bar. And the space around that bar gets a little bit compacted over time. But the big change in the picture is how much LNG comes in to meet the rest of US demand.

I wanted to talk about what the uncertainties are around this supply forecast. First off Mike mentioned, and if you look in the detailed version of the preliminary report, there's much more color around this issue than I am going to go into here.

But it seems pretty certain, pretty easy to demonstrate that there are increasing production costs. The cost of producing gas is increasing, significantly increasing and at the same time we've got declining production per well.

And I am going to show you in just a minute, or do show you in the detailed, the more detailed report, that that's not just total wells where production is declining but it's production per new well. Production for a new well that gets drilled, that production is declining for every new well that we drill. They produce less and less. And Mike talked about that.

He talked about why that's the case when he spoke but I'll give you some other ideas around that that sort of go beyond the notion that all the finds, the gas reservoirs that we're finding are tinier, and tinier and tinier so it's inevitable that we'll produce less. But I think there is a little bit more to it than that that's useful for us to keep in mind. And that has to do with the investment reward versus risk evaluation that producers make as they drill.

Producers right now because of pressures from Wall Street, because of the fact that it's less risky with new technology, are able to focus on in-fill drilling and drilling unconventional reserves. Those unconventional reserves cost more but they're less risky. So when you multiply risk times costs they look more favorable than conducting a lot of outright new exploration.

And the other thing that we know, if you spend a lot of time looking at this data, is that we don't drill a lot of true exploration and production wells, exploratory wells anymore. We actually drill very few.

So with all those things going on the one thing to keep in the back of your minds that this sort of blanket claim that, oh my goodness, we can't ever produce more, probably to some degree confuses cause with effect of what producers are actually doing versus what they can do.

The second kind of key area of uncertainty there with supply is we've mentioned the areas that are closed to drilling. A lot of people probably don't even realize that the Energy Policy Act last year prohibited drilling under the

Great Lakes. And not only drilling for gas under the Great Lakes, there's a lot of gas in Michigan. Not only does it prohibit drilling under the Great Lakes but it says that you can't even drill a horizontal well from onshore underneath a lake.

We also had a ban adopted last year in Montana. No gas drilling on the front range of the Rockies in Montana. A senator from Wyoming just last week announced he is going to propose the same thing for Wyoming.

The Colorado Oil and Gas Conservation Commission is now having its makeup changed to try to make sure that it is not a group that favors producers but that it incorporates folks who are interested and support conservation as well as just production. So that it isn't for that agency to sort of encourage production but to actually encourage conservation of what we have to produce.

So there's some changes going on, for example, in the Rockies, as well as what happened with the Great Lakes that have an impact on what we can actually drill of that nearly 1100 Tcf resource base that we've got.

We had some questions earlier about how much Canadian gas was available to the US and that's another big uncertainty. If you look in the more detailed report, I'm going to forget which graph it is, but there is a figure there that gives you some data on forecast production from Natural Resources Canada and then it also provides Natural Resources Canada's forecast of how much of that gas will get exported to the US.

And the difference in the slopes of the two lines essentially represents what Natural Resources Canada thinks will get used to support tar sands production in Canada. And/or otherwise meet growing demand for natural gas in Canada. Which I think, if I remember correctly, is actually relatively small. So it is fairly safe to say actually that most of that is tar sands.

Now there are other folks who think that Alberta will decide to build nuclear power plants to provide steam for the tar sands production and that there won't be any increase in natural gas demand. So the real point is just to identify that there's a lot of uncertainty around what will really happen with how much natural gas gets used to support tar sands production.

And then the other point I want to make that is a key supply uncertainty, and I think we've talked about this earlier in the day, is uncertainty about LNG access and costs. We talked about the geopolitical issues. You can convince yourself that perhaps there won't be as much LNG available as we think other times, so there's a lot of uncertainty around that.

I had forgotten that I included this table. I mentioned it earlier but let me, let me walk you through what this tells you. This is some data provided by Lippman Consulting. It's out of their supply model actually, we were able to use it with George's permission. Kevin Billings I think may have mentioned Lippman earlier.

This is recorded data on production, the number of wells drilled. And we can use that to calculate how many wells it takes to produce -- And I just selected because it's a nice round number, 2.5, 20 cubic feet per year. So if you look at the column that says, Bcf is the label there. You can see that back in 1999 we were able to produce about .162 billion cubic feet for every new well we drilled. And last year the data suggest that that number was cut nearly in half, .091. Pretty dramatic change.

Now the import that that has is this. Back in 1999 with that kind of production per well number you could drill 15,427 wells and produce 2.5 Tcf new production. Today it takes 27,414 new wells to produce 2.5 Tcf of new production. So that right there is the key sort of element behind this notion that you have to keep drilling, you have to keep drilling in increased quantity.

This has nothing to do with depletion. This has absolutely nothing to do with how much gas we produced last year that we can't produce this year because we already sucked the gas out of the well. This is just identifying the fact that for every new well we drill we're drilling wells that produce less.

ASSOCIATE MEMBER GEESMAN: What is going on with rig count?

MS. ELDER: The rig count actually keeps climbing. I don't think I have that graph in my hip pocket but I often have a graph handy that will show you the rig count increasing and sometimes I'll show it to folks even with the number of wells drilled or production when cited.

I think it's in the range, if I'm not mistaken, right now about 1400 rigs drilling for gas. And if I go back to about the year 2000 there might have been a peak that was close to 1,000. And then as prices dropped in 2001, 2002, 2003 that fell off back down to about 750. Maybe 700, 650. And then as prices rose again it's come back up and it's gone steadily up.

But the point that that brings us to is recognizing that if you're going to drill this many wells you have to have a lot of rigs, an increasing number of rigs, and you have to have a lot of people who know how to man them.

I mentioned sort of earlier this notion of cause versus effect. Mike had mentioned as well earlier that there were some reasons to think that maybe you could produce more gas. Essentially I would probably tell you if you gave me the right amount of vodka, or maybe if you don't even, that we can produce more gas.

Sure we can produce more gas out of that 1100 trillion cubic feet resource base we've got, it's just a question of how much you want to pay to get it out. And what the model is telling you is that with the LNG cost that it's got in it that it is economic to use that LNG instead of to produce more gas.

So then having said all of that we built what I call a supply heuristic. And it's really a snapshot of supply at any given moment. It's pretty dang simplistic. But in essence it says that you can think of US supply as being comprised of last year's domestic production, subtract out what you'll lose due to depletion, add to that the production that you'll get from new wells, recognize how much gas you can import via pipeline, typically from Canada, add in LNG, and that's the US supply mix.

Now I can add to that equation and rearrange it. Just move things to the other side of the equal sign with a modicum of algebra. And what you see is that I can understand the difference between US demand and US supply pretty quickly with this picture that I'm going to create. Basically demand minus supply is the gap, if you will, and you've got to figure out how to meet the gap. The gap could be met with LNG, arguably, or you can go back and try to adjust demand, reduce demand, or see if you can figure out how to increase supply. I mean, those are your fundamental choices.

I think Dave Arthur from Redding today

asked a question that was kind of headed at that. If the issues or the variables that you've really got on the table are demand and supply, and LNG is a policy matter, which one do you try to manipulate or which one do you try to effect?

If you look at the preliminary report there's a set of tables in there that probably look far more confusing than they need to be. They are Tables 10 through 12 and they provide you with the detailed numbers behind these three cases. We did a reference case, a high supply case and a low supply case using this heuristic. The reference case just replicates what staff has gotten out of NARG. It just takes these variables, these simple variables that I talked about, depletion, the number of wells you drill and how much production you get per well, and basically takes our supply quantity and says, okay, if that's how much supply we can produce how do we do it. How many wells do we have to drill? What production per well do we get to do it. What kind of depletion there was. Just a quick snapshot way of thinking about supply.

You can see here in this table the listing of what the key assumptions were and the gap, if you will, which in the model results is met with LNG, that we get from doing that. We have an aggregate depletion loss and we use this across all three cases of minus two percent. It turns out to be roughly equal to two, two-and-a-half trillion cubic feet a year.

But look here at the difference in the number of wells that end up having to be drilled by 2017. In the reference case we have 45,212. The high supply case is lower because we've got much more supply coming out of those. And in the low supply case I constrained that only 30,000. That 30,000 is roughly what we drilled last year.

In the production per well, both in the reference case and the high supply case I let those be the same at about minus four percent. Notice that the annual rate of decrease over the eight years that I had from the Lippman case was higher, it was almost 7 percent. I didn't have the guts, if you will, to actually set that four percent at minus seven percent.

And then we have the number, the percentage here on the rate of decrease in the amount of gas that we can get from Canada. All told the reference case gap between supply and demand is about seven trillion cubic feet per year just for the US. It's not North America, this is just the US.

In the high supply case, which actually pretty closely mimics EIA's reference case, that gap ends up being about 3.3 trillion cubic feet a year. And in the low supply case, where you can see what the key changes are that we made there. All we did between the high supply case and the low supply case was change the number of wells, reduce the number of wells drilled by about 5,000 per year. We let production pretty well actually settle out at zero.

And I'm looking at this and going, but those numbers are reversed. The low supply production per well should be minus four percent and the high should be zero. And that is a typo that is entirely my fault. It makes this very confusion. So my apologies for that.

The other key difference there is the change in Canadian imports. And those minor changes create a change in the high supply case versus the low supply case of almost six trillion cubic feet per year. Actually almost seven trillion cubic feet per year.

So the real point is, just some very minor changes in how you think the industry works have a really big impact on the total supply that gets produced. US domestic production. And that then has large implications for the amount of supply that has to be made up with LNG.

Now somebody else I heard ask, and it might have been Kevin Billings so I think he's probably left already to catch his airplane. Can we even get that much LNG? If you are really saying that we need in the EIA case -- EIA says we probably will end up using about 3, 3.5, 3.4 trillion cubic feet per year of LNG.

We've got a reference case here using our staff assumptions out of the NARG model that shows seven trillion cubic feet. And then my draconian low supply case increases that number by another three up to ten trillion cubic feet. Can we even get that much LNG?

And that's sort of in some respects what Jim Jensen was talking about this morning. He talks about his total world LNG supply being about 15 trillion cubic feet per year. So if staff's case is seven coming to the US then that is roughly half of the world's supply of LNG coming to the US. And I actually don't know and we could ask Dale later, but I actually don't know what his world gas trade model has got in there as total LNG supply. That amounts to roughly half as I mentioned.

Now when you talk about the other -- There's another graph in Jim Jensen's study that says, it talks about demand for LNG. What he is doing in that is essentially taking his 15 trillion cubic feet of supply and he's saying, now which countries is it going to go to?

And he shows a much smaller number, about 4.4 trillion cubic feet by 2015 coming to the US, than staff has got. Staff's is 7, Jensen is about 4.4. So while the staff reference case is well within the total amount of LNG that Jim Jensen says is available in the world he would have probably only about 30 percent of that actually come to the US.

Now we could actually take this heuristic that we develop, these tables that are in Tables 10, 11 and 12. We could actually take that. We could constrain LNG in that table and we could tell you what kind of production numbers. How many wells you've got to drill and what production has got to be in order to produce enough gas, if you will, to make up for what we lost in LNG.

It won't tell you anything about the economics of doing that but it will tell you what the production business ends up having to look like. And we'll give you a sense of how, whether or not you believe or you can make yourself believe that that could actually happen.

The other key piece of work that we did, and Youssef may interrupt me at any moment yet again. The other piece of work that RW Beck did had to do with oil prices and the relation of natural gas and oil prices.

And when Dale said this morning that he wants everybody to hold up their hand and repeat after me, natural gas prices are not related to oil prices, I wanted to stand up and cheer. Because I tell people that all the time. And then I go, but having said that, maybe it's a little more complicated than that. But I like to believe that and I like to say that. Then I step back and I realize, well, there are some linkages between the two.

Let me tell you a little bit about some

of those linkages. They really happen because higher, you have a lot of natural gas that's produced in association with oil. Higher oil prices increase oil production but then that associated amount will also increase. So if you increase oil production due to higher oil prices you probably get higher natural gas production.

You also will see the E&P budgets of a lot of different oil companies increase with oil prices. So oil prices go up, their earnings increase, they realize that they can plow more of their earnings back into the oil paths, they do more drilling. And so they spend that on more capital, capital projects.

It's also the case, I think folks have mentioned this earlier, that you had LNG contracts particularly in the Pacific market that were indexed to oil prices. In large measure that may have happened because there was a lot to use and because that gas actually displaced oil.

There are at least -- a number of folks who have suggested or at least I've heard suggest who were involved in some of those negotiations delivering LNG to Japan that that may not be, always be true. That there may be some -- I'm trying to think of the right word. Some change in the pressing mechanism of some of those contracts, or at least an openness to discussing them.

But also realize that the contract, for example -- in particular the contract to export US natural gas produced in the Cook Inlet of Alaska that goes to Tokyo Electric has been in place for 40 years. And my understanding from some of the folks at Marathon Oil, who sell that gas to Tokyo Electric, is that you don't just walk in and tell the Japanese that you want to link the price to a natural gas price rather than use the Japanese Crude Cocktail that has been constructed over the years, even though there might some willingness to move in that direction.

There are also some competitive links between oil and gas. There have been competitive substitutes, primarily in the EG sector, to some degree in the industrial. And you'll find a lot of people around who think that because that used to be the case -- You know, I can even remember when there were PG&E power plants that were switched to oil. And I remember the phone call in which El Paso was told, the power plants will stay on oil until you drop your price.

Can't do that anymore. So a lot of the notion that oil and gas prices are linked really I think has to do with this legacy of folks who remember that you used to be able to switch gas for oil. And they just don't quite realize that you can't do it anymore.

Some numbers. These are natural gas and equivalent oil prices. There are nominal dollars per MMBtu. What you're looking at is the price at Henry Hub, which is the pinky kind of price and the blue kind of price is a crude oil price.

And what you can see when you look at those, you know, having said that there's some reasons why on the E&P side, there's some reasons on the capital investment side that they might be linked, then you look at the graph. And you can see really key periods here where there's just no relationship whatsoever.

In large measure that is -- I shouldn't say in large measure but to some degree that's what Dale was talking about this morning. That there is certainly no notion that just because there are six MMBtus in a barrel of oil that the way you forecast natural gas prices is to take the oil price and divide it by six.

And I've had people say that to me. I've had people say to me, Catie, why is your forecast so low? Oil prices are at 60. Divided by 6 the gas price should be 10. People say that all the time. But it's just wrong.

Here what you see in particular is you can see a period in the late '90s, 1995 through 1998 or so, where gas kind of bobbles along on its own. There is no real relationship to oil prices. Then you can see a period where they kind of move together then you can see another period where they don't.

You can see spikes here, particularly in winter. In late 2000 or early 2001, again in 2003. Again right after Hurricane Katrina where natural gas prices spiked far above oil prices. And in the post-Katrina environment we have natural gas prices far below oil prices. Now let me go to the next graph.

I put more colors on it to make sure that you were totally confused. The green price here is natural gas. And we added to this resid and distillate because the other argument that we hear quite often are people who will say, natural gas will trade in a range relative to oil where the boundary on the top is set by distillate and the boundary on the bottom is set by resid. And what you can tell looking at this graph is that ain't true either.

You can see that natural gas really trades above distillate. There is only point at which it trades above distillate. But when you look at the resid price you often see here natural gas trading below that resid price. And by the way, the resid price tracks crude really closely. And that makes a lot of sense because resid is not that different from crude, whereas distillate is.

And the question that I would ask, I don't know the answer to it but since I'm a consultant I get to ask questions that I can't answer, what you see is that the gap between distillate and resid -- here I could use the pointer if I knew how to turn it on. I got it.

See this gap here between crude, crude down here, crude and resid down here and distillate up here. So how it gets bigger? It's relatively constant for a really long period of time. For like '03 versus 1995. Through that period if you graphed a delta between those it's pretty much a constant. But beginning around the middle of '03 on to the end of the period that gap widens. My guess is it's refinery capacity but I don't know that for sure.

So the bottom line that I need to articulate before I switch to the next page, I get in a hurry and ahead of myself here, is that the relationship -- there is a relationship between oil and gas. As much as we like to say that there isn't there is a slight relationship between the two. I think the words Dale used this morning is that they're correlated but one doesn't drive the other. The relationship is not a constant. And that's probably the big take-away here is that the relationship is not a constant, it's not simple. It's actually quite complex and it's hard to explain.

DR. HEGAZY: One thing that we have to realize, and it's from different academic and industrial studies that have been done in this area, is gas has a phenomena to phenomena that does not quite affect oil as much. One is the seasonality and the other one is the storage. The storage has a tremendous impact on gas prices and on the gas industry.

Since we're modeling here on an annual

basis the two of them are not captured. In other words, if we are to do a monthly modeling of natural gas prices and natural gas supply and demand, a little bit of link between oil and gas might, might exist.

As a matter of fact some very recent study has been done by the Rice University Energy Center, which I think Mr. Medlock works there, has shown that on a monthly basis, and if you account for seasonality and if you account correctly for storage, you will see some lags around two or three months between oil prices and gas prices. But not as strong as people might think.

MS. ELDER: Youssef has actually done kind of a literature review on this subject looking at a number of different academic studies. There is a very short summary of that work in this preliminary report that has been published so far and there is a longer discussion that he has prepared that we would expect would go into the long version of the report when that is released.

Let's talk about the price results. It would not be correct to say that RW Beck has somehow validated staff's forecast. We haven't done that.

What we have really done is we worked alongside staff asking questions, poking Leon in particular because we all like to pick on Leon. And he dishes it back too as we all know so it's a good thing. So we have asked questions, we've probed, we've made suggestions. We've said, have you looked at how this result compares with EIA's forecast, for example. So we've done some benchmarking.

But I have to tell you that RW Beck may produce a gas price forecast that is different or the same from this forecast. And I can't even tell you if it would be different or the same. But we did do that for a number of clients and it may well be different than this forecast.

We have looked at EIA's most recent annual energy outlook, which we've mentioned earlier, and I think it's figure 38 in the preliminary report. And if flip the page here it will show you, this is figure 38 from your longer report. Bill Wood mentioned earlier that I would show this to all of you.

This is a comparison or a behchmark, if you will, of staff's reference case out of its NARG modeling effort against what EIA put out in its annual energy outlook in February. And then there's another, the pink line is a price forecast that is prepared for another set of work that the Commission has underway. It's part of the IEPR.

It's the scenarios project where the gas, some electric production cost modeling is being done by Global Energy. And they also then have the ability to take that projection and plug it back into their gas price model and produce a gas price forecast.

They took their fall reference case, their fall 2006 reference case, plugged in -- and I'm giving you the short version of what they did. Plugged in EIA's oil price forecast and the pink line that you see here is the result. So they by plugging in EIA's oil prices were able to make their reference case match EIA relatively closely.

Now the black line here is staff's reference case. And what we see here is that after about the first five years, '07 through 2011, after that the three price streams are pretty close. You see the seesaw effect that we talked about earlier a little bit in staff's case but by and large the range of the numbers is relatively close.

Now the other thing that we plotted on here, not because we believe this is a good idea but because everybody does it, is we have plotted NYMEX futures prices. These were gathered at the end of April and I think in the middle of March if I'm not mistaken. And Youssef will correct if I got that wrong. Just to show you how close. We know that Global's forecast actually is adjusted for NYMEX, explicitly just for NYMEX in the first 24 months and then I believe the second 24 months they have a mean reversion process that converts that forecast back to their fundamental case.

And we don't exactly know what EIA does in the early years but we believe that if they could tell us what they really do we'd be fascinated by it. What we know is that they won't tell us what they really do.

We also -- One of the benefits that comes out of the annual energy outlook is that EIA will publish a comparison of their forecast to a whole slew of other forecasts. They graph energy ventures analysis, and EEA, SEER as well as some other work that Altos has done. And they provide a table that's buried in the back pages of the outlook that compares all these different forecasts.

We went and grabbed those and we plotted those, the prices for 2015 and the prices for 2025, which are the ones that were easily obtainable out of that table back at the end of the energy outlook. So the light bluish kind of column is 2015 and the one with the diagonals in it is 2025.

And what you see here is that when you get into those out years staff's reference case, or their preliminary results at any rate, are actually, particularly out in the out years, pretty high relative to everybody else. And at 2015 which is the end, close to the end of our reference period of 2017, that number is not a lot different than several of these others. So, you know, when you look at what the staff has done relative to what other folks have said out there, it's pretty close.

And I think Herb's graph from SoCal provided their forecast and had a comparison of staff's number to SoCal's forecast and I think that we could probably incorporate that as well.

By way of summary, if we talk about the variables that might create higher versus lower natural gas prices, this is the list of variables that we've developed. Sort of putting everything all together. We've got some that are policy-related or policy-driven that we've talked about before here. We've got the demand variables. Demand side variables that have a big impact. And then the supply and infrastructure-related variables that we've really talked about in that supply, that are behind that supply heuristic, if you will. Conceptually behind that supply heuristic.

Now the other part of what we do, particularly when we're picking on Leon, and he's going to get me for this, is we have really kind of taken responsibility for trying to create, you might call it a punch list or a checklist, a to-do list. But this is a list of things that we have noticed as we've talked to the staff and we've looked at the results that are kind of the key questions in our minds.

But we think that as you move from this draft case or this draft reference case, preliminary reference case, as you move after this workshop to really finalize this case, that these are the things that need a second look or some time spent on them to talk about.

One of them would be the LNG assumptions. We mentioned that before, I don't need to say a lot more about that.

We're aware now that the model has got a huge increase in demand for gas in the eastern US due to carbon regulation or emissions treatment and so forth. We need to understand and be really comfortable with that number. And we also need to think about what the implications of that could be for the WECC that we haven't captured. Some of that may be captured in the scenarios project, by the way.

Mike Purcell and I might be slightly confused about how the Rockies land access restrictions are treated. There are some that are in the model, we think there are some others that are not in the model that probably ought to be in the model. But somebody has got to go sit down and take a look at that and make sure of what we've actually done. What's actually in there and what actually ought to be in there.

We think we have not spent enough time looking at the results for the impacts on the Pacific Northwest and Northern California. And I think the reason that kind of happens naturally is that when you look at the model results all the action is kind of in Southern California. You've got Costa Azul coming on and delivering lots of gas. That backs out some Southwest gas out of El Paso's southern system. That sort of, you know, thing is going on.

And you look at the Northern California results and the flows don't seem to have changed a lot. But it would be worth it to sit down and look at not only, I think as somebody mentioned earlier today, actually calculating the capacity factors on the system but just taking a look at what changes and make sure that we're really comfortable with that.

We also need to take another look, I think, at the impact of dry hydroelectric conditions. The models and virtually everybody who does this knows that this is how we all do it but we all assume average or normal hydro. That's the expected case. But we need to -- As 2001 showed, we need to worry about what happens in a dry hydro case.

There are potentially some impact of some other policy scenarios that would come out of the integration of these results with the modeling results coming out of the scenarios project. So we have to be cognizant of how those things fit together or figure out how they fit together and be cognizant of them.

We also thought it was potentially the case that even while there is not a lot of substitution for gas versus oil here in the US anymore for a lot of reasons that arguably there may be some substitutability globally and we're not exactly sure that we understand how the model treats that. So that's something that is probably worth at least some time discussing further and making sure that we understand it well.

Now the last thing that is on my list here. And this may go to the question that Commissioner Geesman answered earlier about modeling tools and scenarios that actually capture uncertainty. The use that staff is making of the NARG model we understand there are some ways that you could actually use NARG probablistically. And those need further explanation. Explanation, they need further exploration. It was an E word, I just couldn't say the right E word.

We would recommend spending some more

time to understand how staff could use NARG probablistically to come at some of these issues rather than take the very broad brush approach that we have put to work here, which is to say, demand could be higher or lower by this much. Supply could be higher or lower than this much. These are the issues that you need to worry about. But you probably can use the existing modeling tool in a much more robust way.

That's our sense. But again, we're not, we will not -- Youssef and I will not claim to be NARG expert users but we do understand there's some capability there that is not being exploited fully at this time.

And with that, that's all. Questions? Nobody looks like they're asleep. George, right?

MR. CLAVIER: That's right, very good. I'm George Clavier with PG&E. And the question I had probably is better addressed to staff as opposed to Catie.

But I noticed in the sensitivities chapter in the report you ran sensitivities regarding adding additional LNG supplies into Costa Azul. And you reported the quantitative effect on flows but I didn't see any price effects. So my question is, do you intend to report those out in the future? I guess that's my question.

MR. BRATHWAITE: Yes we did do the four sensitivities. These sensitivities we are still trying to work on them. Before we finalize them we do not want to put out the exact results that we got out of the model. Now some of the results that we have so far are somewhat, shall we say, within the precision of the model and we want to discuss that internally a little bit before we put the results on the street, so to speak. We are at the interim process, shall we say, before we finalize those products, yes.

MR. CLAVIER: But your intent is in the final report those sensitivities will be released?

MR. BRATHWAITE: In consultation with the IEPR committee and the Natural Gas Committee. It is our intent, yes, to do so.

MR. CLAVIER: Okay, thank you.

MR. BRATHWAITE: Sure.

MS. ELDER: Yeah.

MR. COWDEN: Bob Cowden, PG&E. This is a follow-up question to George's. I think it's back to Leon. On those sensitivities in the report you talked about the Oregon LNG case not having any price benefits to California. And I guess, I think that's a function of how you modeled the Oregon LNG case. Where you just put those supplies into the Pacific Northwest demand.

I think if you created another sensitivity or you modeled a Southern Oregon LNG project that I guess delivered those supplies directly to Malin, I think you'd find that there were price benefits to California in that type of case. How you model an Oregon LNG project kind of is dependant on where it is, whether it's in Northern Oregon or in Southern Oregon.

So I don't know if you were planning on doing that in any more work you were looking at.

MR. BRATHWAITE: Well, I mean, I cannot definitively tell you that we are planning to do any more work in terms of doing the slight restructuring that you are suggesting. But it is certainly something that we'll take into consideration because I think you are absolutely correct. The architecture that we have in the model up in the Pacific Northwest will certainly affect whether we see the price effects that may be possible if more LNG is inserted into the

Pacific Northwest.

MR. COWDEN: Or if you deliver it directly to Malin.

MR. BRATHWAITE: If delivered to there, yes, yes.

MR. COWDEN: Okay, thanks.

MR. BRATHWAITE: Most certainly yes.

MS. ELDER: Dale.

DR. NESBITT: Two questions, Dale Nesbitt, Altos, that Melissa asked that are great questions and require just a little bit of attention. Number one, why the bump in 2013 in the staff work. That's a really important question. That's when the carbon legislation starts by assumption. So what we said in the model was, we have a $7 a ton carbon tax starting in 2013. That was our attempt to stimulate a Binghamon style, I call it tepid because it's not an extreme.

Now that's very interesting. What does that do? Suppose you didn't have it. Well we don't build new plants for awhile, we just go to worse and worse heat rates at the margin, okay. And then sooner or later you've got to start building new capacity. As soon as you pop a $7 carbon tax it accelerates the build rate and you saw that curve flatten. It was a great question. Alternative carbon scenarios are going to give you alternative gas burn growth rates and it is quite sensitive to that.

The second really good question had to do with pipelines and reserves and that kind of thing. One of the things that staff had intended to do this year, we never got around to it, was to use the short-term model that you've never used. It's monthly, going forward ten years. And one of the issues with regard to pipeline retirements really isn't annual load, which you focused on pretty much completely today, it's monthly load.

So your point is exactly right. They don't retire these pipelines because if in one month out of three years they're going to carry a critical load those pipelines will stay in service. People will maintain their firm transportation requirements on those pipelines to hedge against that. That's really the reason in the real world, you know.

You'll see power plants in cold standby and various stages of cold standby by analogy. Because just as everybody said, even in a -- one thing we know is that we're going to have volatility and variability in load. And so in the model that has been used to date by staff, the long-term model which averages out or annualizes these effects you're not going to capture those critical issues. But in the short term model, that I don't know what the future of it is, it picks those right up.

A classic example of that we've seen in the last two years across the Atlantic Basin. We have seen LNG cargoes come to the US 10 to 11 months of the year and go to the UK and Zeebrugge for one month. Well if you model that on an annual average basis you'd be pretty naive, overstated for emphasis. So those are good questions.

One other thing about oil that's worth characterizing, and I've done quite a bit of refining modeling in recent months, in part for the Commission. Storage matters. People do store product, a lot of storage. But most important, what's going on in the world refinery sector, Catie was right on it, is that the cracking margin, which is the difference between the heavy products and the light margins, has gone to infinity minus a little bit.

And so everybody has retrofit their refineries, which means there is no residual oil produced, overstated for emphasis, in the Rotterdam market, that's all of Europe, or in any of the North American markets. That's what's broken, the link. More and more. And Catie is quite right, it's not a complete break, but the link is breaking between residual oil -- it's always been broken between the high-end refined products and natural gas.

So I hope that helps on the pipeline reserve. Pipelines are held as reserve capacity, we know that, by people who want to hedge against dry hydro, a hot summer, that kind of thing. That's why they stay alive.

MR. TAVARES: Okay, any more questions, comments?

MR. PAK: Are you asking for questions to end the day or just on this presentation?

MR. TAVARES: Well, to end the day. I mean, go ahead.

MR. PAK: I'm glad you stuck around, Commissioner, because this is really going to be directed at you. We have offered to the staff that we're going to provide comments on June 15, written comments, and we're basically going to provide them with our data sets with respect to supply that we believe will be reliably coming out of three different areas, California production, San Juan Basin production and Western Canadian production.

We believe that the staff data sets are far too optimistic for supply coming from those areas to California so we're going to provide you with our updated internal, homegrown forecasts that are based on our own review of data at the production sites as well as our own experience in having invested in some of the wells in some of those areas. Just to give -- And we're hoping that the staff uses them as part of their scenario analyses.

And just to give you some of the bona fides of our forecasts, those are the ones that we began developing pre-2000 and that has to date resulted in Sempra's commitment to invest over $3 billion in the development of infrastructure to build, to bring LNG to the United States and into California particularly. That's $3 billion of private, at-risk capital that has no guarantee of cost recovery other than through private contract and our operation and delivery.

We spent a lot of time in rooms with companies whose earnings, where if you compare earnings our earnings are about one day in their annual view. Their market caps are sometimes three to two hundred times ours. So if you think about a company our size investing in this industry it will give you an idea of the confidence that we have to hold our own and I think we have.

I think the bottom line, if you look at the Jensen report, and we'd love to see more of the information that he was relying on, we would basically agree that investment in any portion of the LNG supply and delivery chain, it is not for the faint-hearted. It is not for those whose views are formed by short-term perturbations and any portion or segment of that market or the collateral markets and ancillary markets that it affects or are affected by it.

It is not for the uninformed. So we hope that with those bona fides you understand that we believe in these forecasts. We think the state of California should take notice of them.

We certainly have invested a considerable amount of capital on at-risk basis based on these forecasts.

The other point that I would want to make, and maybe this is a follow-up to one of the earlier political scenarios that we had suggested that the staff, that they run. And that had to do with the South Coast Air Quality Management District's proposed air quality standard.

I can't believe we have gone through the whole day without talking about Senate Bill 412 and the potential impacts that bill could have on gas supply here in California. You may know that that bill would require this Commission by the end of 2008 to perform a needs assessment for LNG.

We believe that you should take this opportunity in this Integrated Energy Policy Report to basically do that and address the issue of whether California, it's utilities or any other parties here should be going long on LNG. Sempra certainly has taken that position.

The Federal Electricity Commission in Mexico has taken a long position in the supplies coming out of Costa Azul. And we think it's a good time for the state to take a look at the issue of whether you should be taking a long position, either with respect to capacity or supply, represented by LNG supplies.

We're obviously very bullish and we'd love nothing better than to have our forecasters and our planners sit down with you and your staff as you develop this Energy Policy Report to get a jump on SB 412 as well as to deliver what we think can be a very important IEPR to the state at the end of this year.

So I just wanted to let you know that we are going to be filing written comments next week on these topics and we hope that we can work with the staff to develop at least one of the outlier scenarios for supply to California.

ASSOCIATE MEMBER GEESMAN: I appreciate your comments, Al. Let me ask, are there supply basins where you feel that the staff's assumptions have been too pessimistic?

MR. PAK: We have not. I think that when we first came up here for the 2003 IEPR our analysts, one of our analysts was characterized by your staff as Dr. Doom because his supply forecast was pretty pessimistic across the board relative to all of the information that you were looking at. Our information across the board continues to be more pessimistic.

There are things that we haven't, we don't reflect in our forecast. Things like, is there going to be a next breakthrough technology development in oil drilling, well drilling, recovery of natural gas from deep supplies. We just don't foresee that happening in the time frames necessary to out-compete for contestable markets against LNG supplies that we're certain will be here beginning in the first quarter of 2008.

ASSOCIATE MEMBER GEESMAN: Do you envision having competition from other LNG terminals on the West Coast?

MR. PAK: It is our official position that we don't comment on other terminals here in the state but we have always thought that there was room for more LNG to be imported than is, than could be imported through the first phase of the Costa Azul project. That's why we have spent a lot of money and time pre-constructing for an expansion of roughly 1.5 Bcf per day.

We believe that we are positioned to compete against any terminal that might be built on the West Coast. If they are more competitive, if they have supply in the chain that would out-compete us then we might not build the expansion. But based on the shipper response to our open season that we held last year we think we're competitively positioned. If there is another terminal we'll have to relook at that based on the shipper response to it.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. TAVARES: Next steps. Any more comments, questions?

Okay. Next steps. We would like to receive your comments by next Friday. Not this week but the following week, June 15. Once we get your comments and suggestions we'll regroup, get together, talk to the Commissioners, talk to the advisors, and see where we proceed from there. We are expecting to finalize the report by the end of July. It can happen before but this is what we are expecting to do now.

Again keep in mind there is going to be another workshop that will touch on natural gas that will be August 13. And I don't know whether this has already been advertised or not but this is what we have been given. That we are going to be discussing not just natural gas but how to integrate natural gas into the scenario project that is underway for the 2007 IEPR.

And with that, Commissioner Geesman, if you have any concluding remarks. That's all we have.

ASSOCIATE MEMBER GEESMAN: I think it has been a very productive day. I want to thank you all for participating.

MR. TAVARES: Thank you very much and we'll adjourn.

(Whereupon, at 4:25 p.m., the Committee workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 18th day of June, 2007.